2018 ANNUAL REPORT

Emera

TABLE OF CONTENTS

Full page: Our team members work hard to improve the infrastructure serving our customers, such as this new, higher-capacity transmission tower in Nova Scotia.

WHY INVEST IN EMERA

Customer demand for cleaner, affordable, reliable energy delivered safely is steadily increasing. Through our regulated electricity and gas assets, and exploring innovative solutions for current and future energy needs, Emera is well positioned to meet that demand while delivering sustainable, growing dividends to our shareholders.

SUPERIOR SHAREHOLDER RETURNS

Five year annualized total shareholder return of

12%

compared to 6% returned by the TSX Capped Utilities Index and 4% returned by the TSX Composite Index

Representation in the TSX Composite, TSX Capped Utilities, TSX60 and MSCI World Indices

STRONG EARNINGS

Adjusted earnings per share CAGR* of

8%

over the last five years

90%

of earnings derived from regulated businesses

65%

of earnings from US operations

GROWING DIVIDEND

Dividend per share CAGR of

10%

over the last five years

4-5%

dividend growth target through 2021

GROWING OPERATING CASH FLOWS

12%

CAGR in pre-working capital operating cash flow per share over the last five years

5x cash flow from operations coverage of dividends

Investment grade credit ratings

VISIBLE GROWTH PLAN

$6.5B

capital investment plan to drive rate base growth through 2021

6%

rate base growth through 2021 driven by Florida investments

All figures in Canadian dollars and as of December 31, 2018 unless otherwise indicated.

* Compound Annual Growth Rate.

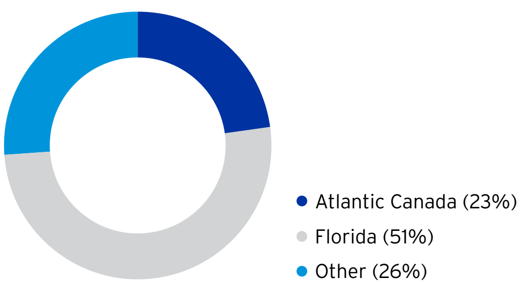
EMERA AT A GLANCE

From our origins as a single electric utility in Nova Scotia, Emera has grown into an energy leader serving customers in Canada, the US and the Caribbean. Our companies include electric and natural gas utilities, natural gas pipelines, energy marketing and trading, and energy services.

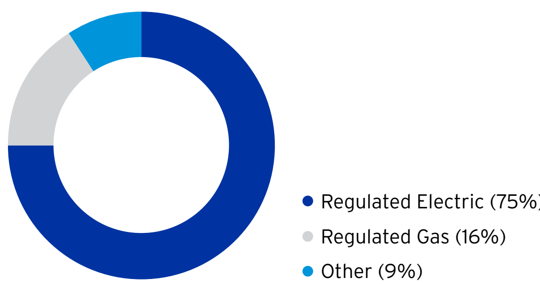
Adjusted Revenue*

As of December 31, 2018

By Region



By Revenue Type



* Adjusted revenue is a non-GAAP measure which excludes mark-to-market adjustments.

TAMPA ELECTRIC

Vertically integrated electric utility serving 764,000 customers in West Central Florida.

PEOPLES GAS

Natural gas utility serving 392,000 customers in Florida.

NOVA SCOTIA POWER

Vertically integrated electric utility serving 519,000 customers in Nova Scotia.

NEW MEXICO GAS

Natural gas utility serving 530,000 customers in New Mexico.

All figures as of December 31, 2018 unless otherwise indicated.

EMERA MAINE

Transmission and distribution electric utility serving 159,000 customers in northern and eastern Maine.

EMERA CARIBBEAN

Vertically integrated electric utilities serving 184,000 customers on the islands of Barbados, Grand Bahama, St. Lucia and Dominica.

EMERA ENERGY

Energy marketing and trading, asset management and optimization in Canada and the US.

EMERA NEWFOUNDLAND & LABRADOR

Owns and operates the Maritime Link and manages Emera's investments in associated projects.

EMERA UTILITY SERVICES

Utility services contractor working in Atlantic Canada and other regions.

EMERA NEW BRUNSWICK

Manages the Brunswick Pipeline, a 145-kilometre natural gas pipeline in New Brunswick.

EMERA TECHNOLOGIES

A start-up company focused on finding ways to deliver renewable energy to customers.

$32B
Assets

$6.5B
Revenues

2.5M
Utility customers

7.5K
Employees

Full page: We are a leader in the transition to clean, renewable energy with one of the highest percentages of wind integration in Canada.

All figures in Canadian dollars and as of December 31, 2018 unless otherwise indicated.

2018 FINANCIAL HIGHLIGHTS

2018 dividends were up **7%** to **$2.28** from **$2.13** in 2017

$2.88 adjusted EPS, up from **$2.46** in 2017

$1,806M operating cash flow (before changes in net working capital), up from **$1,297M** in 2017

We're on track to install 600MW of new solar generation in Florida, and we're advancing plans to increase our solar capacity in the Caribbean.

We're making energy more efficient through initiatives like our LED roadway lighting replacement programs.

By deploying smart meters and other innovative tools, we will give our customers more real-time information on energy use. We're on track to deploy 1.5 million smart meters across our electric utilities by 2022.

Full page: In 2018, we put the Maritime Link into service, connecting the island of Newfoundland to the North American energy grid for the first time in history.

OPERATIONAL & ESG HIGHLIGHTS

OPERATIONAL

$1.6B
Maritime Link investment placed into service, on time and on budget

832MW
of renewable capacity installed

$18.1M
invested in our communities, including a special $5M contribution to establish the Emera & NB Power Research Centre for Smart Grid Technologies*

ENVIRONMENTAL

16%
reduction in GHG emissions since 2005*

$1.7B USD
invested in Florida, including 600MW of solar projects and the modernization of the Big Bend plant

On track to add
6M
new solar panels at Tampa Electric by 2021

600MW
of grid connected wind capacity in Nova Scotia – one of the highest wind integrations in Canada

SAFETY AND EMPLOYEES

852
proactive safety reports for every 100 employees

83%
employee engagement index based on 2018 survey, higher than industry norm

Named one of
Canada's Top 100 Employers
for 2019

GOVERNANCE

Strong governance
2018 Governance Gavel Award recipient

Consistently ranked in top five for *The Globe and Mail's Board Games*

Named one of Canada's
Best 50
Corporate Citizens in 2018 (Corporate Knights)

* As of December 31, 2017. 2018 number will be available in Emera's upcoming Sustainability Update in 2019.

LETTER FROM THE CHAIR

Emera delivered solid financial and operational results in 2018, as the team remained focused on executing on strategy and delivering results.

In difficult capital market conditions and a challenging year for our industry, we ended 2018 with solid adjusted earnings per share and operating cash flows, and an overall competitive total shareholder return. This underscores our ongoing commitment to delivering shareholder value.

After a 12 month transition period, the Board officially appointed Scott Balfour as Emera's new President and CEO in March of last year. The careful succession plan and focus on continuity of leadership across the business resulted in a smooth transition for the team and the company.

In 2018, the Board worked closely with the leadership team to ensure the right strategy was in place to continue to deliver long-term shareholder value. Core to that work was supporting management's efforts to strengthen the balance sheet, including adjusting the dividend growth target and pursuing select asset sales. We are confident that these significant decisions are the right steps to allow us to strategically redeploy capital to our strongest performing assets and investments.

We are encouraged by the team's commitment to safety, and the progress made to strengthen safety culture, systems and performance. Safety remains a top priority for the Board, and in particular I want to note the tremendous work of our Health, Safety and Environment Committee, which invested significant time in 2018 reviewing performance and overseeing our cross-company efforts to achieve and maintain industry best practices and standards.

We also continued to focus on strong corporate governance, strategic planning and clear guidance and oversight. Across all sectors, we recognize a growing demand from investors for robust corporate accountability and strong environmental, social and governance (ESG) performance. Emera's work in governance and ESG is being recognized. In 2018, we received the Governance Gavel Award from the Canadian Coalition for Good Governance for excellence in shareholder communications, and we continued to rank in the top five in *The Globe and Mail*'s *Board Games* corporate governance report. Emera was named to Canada's Top 100 Employers list for the first time, was recognized as one of Canada's Best Employers by *Forbes*, and was also celebrated by Corporate Knights as one of Canada's Best 50 Corporate Citizens for our ongoing work on sustainability.

We also continued to focus on strong corporate governance, strategic planning and clear guidance and oversight.

Jackie Sheppard
Chair, Emera Inc. Board of Directors

We are proud of our strong track record of representation of women on both our Board and management teams. More than 30 per cent of our Director Nominees for election at the company's 2019 annual shareholders' meeting are female. In 2018, the Board amended its corporate governance practices to make it a requirement that a minimum of 30 per cent of the Board be composed of women.

In 2018, we remained focused on Board succession, making sure we have the right combination of experience and perspective to guide Emera today and into the future. We were pleased to welcome two new Directors, both with exceptional experience at the helms of successful Canadian public companies. Jim Bertram is the former President and CEO and current Chair of Keyera Corp., a leading midstream oil and gas operator. Jochen Tilk is the former Executive Chairman of Nutrien Inc., a global supplier of agricultural products, and the former President and CEO of PotashCorp. Their experience and vast knowledge make Jim and Jochen valuable additions to the Board.

Two valued members of our Board are stepping down in May 2019. Our longest serving Director, Al Edgeworth, will be retiring after 14 years on the Board. His insights into the energy sector have been invaluable and his recent work as Chair of the Health, Safety and Environment Committee has been critical to Emera's progress in these areas. On behalf of the Board, I thank Al for his exceptional contribution and wish him the very best. I'd also like to acknowledge Jim Eisenhauer, who will be stepping down from the Emera Board but staying within the Emera family. Jim is a well-known business leader in Nova Scotia and we have benefitted greatly from his expertise in finance, manufacturing and distribution. After eight years on the Emera Board, Jim will be taking up the role of Lead Independent Director on the Nova Scotia Power Board of Directors. We look forward to his continued wise counsel in this new leadership role.

2018 also marked the passing of our former Director, colleague and friend Wayne Leonard. In his time on our Board, Wayne brought important insight drawn from his extensive career in the US energy industry as former Chair and former CEO of Entergy Corporation. We share our condolences with his family and many friends.

I want to thank my fellow Directors for the dedication and focus they bring to the Board table and for their passionate commitment to Emera's growth and success.

I thank Scott, the leadership team and all employees across the company for the important work they are doing to deliver on strategy and to position Emera for even more success and growth in future.

Thank you to our valued shareholders for your ongoing support that enables Emera to be a leader in our industry, and to create long-term value for our employees, communities and shareholders.

Jackie Sheppard
Chair, Emera Inc. Board of Directors

The team across Emera is committed to collaboration and operational excellence.

From the Caribbean to Atlantic Canada, we're delivering for customers and building strong relationships.

Our team members are committed to working safely, always.

LETTER FROM THE CEO

2018 was a big year in the energy industry as the pace of change towards a lower-carbon, customer-centric future continued to accelerate.

These are broad and important trends that align well with Emera's strategy. However, along with our peers, we also faced broader economic and market challenges. Emera has a proven track record of embracing challenges and finding opportunities in an evolving energy landscape, enabling us to deliver the reliable earnings and long-term growth you expect. I'm proud to say we lived up to that commitment again in 2018, advancing our strategy and delivering on our commitments to you, our customers, communities and the environment.

Last year was also a year of transition for our company as I took over as CEO at the end of the first quarter. As I reflect on the year, I'm grateful to the team and proud of what we accomplished. We strengthened our balance sheet, clarified our growth plans and articulated our funding approach. We focused on investments in renewable and cleaner energy, modernization of aging infrastructure, and customer-focused technologies. Together, the team across the company delivered strong results in 2018 and positioned Emera well for future growth.

DELIVERING SOLID FINANCIAL RESULTS

There is no question we faced some broad challenges in 2018, including the unique impacts of US tax reform on the utilities sector, shifting positioning by credit rating agencies, anticipating and navigating rising interest rates, and changing sentiment within Canadian equity capital markets. These factors put pressure on our business and our share price. To address these challenges, the team took important actions, including adjusting our dividend growth rate, developing and executing on a funding plan to minimize the need for new equity to finance our strong organic growth, and mapping out a $6.5 billion growth plan over the next three years.

While responding to those challenges and positioning Emera for future growth, our portfolio of businesses delivered solid financial results in 2018. Adjusted earnings per share (EPS) increased by 17 per cent year-over-year to $2.88. When normalized for the one-time impact of a state-level tax benefit in 2018, adjusted EPS was up 13 per cent to $2.78. We also delivered strong operating cash flow, before changes in net working capital, of $1.8 billion, a 39 per cent increase over 2017. These results were driven by strong growth in our Florida utilities, consistent growth

Together, the team across the company delivered strong results in 2018 and positioned Emera well for future growth.

Scott Balfour
President and Chief Executive Officer, Emera

from our other regulated utilities and very strong performance from Emera Energy as it capitalized on favourable market conditions.

Given the changes and challenges outlined above, Emera's share price was not where we wanted it to be for much of 2018. For context, our share price was $46.98 at the close of 2017, and we did not see that level again in 2018. In fact, we saw a low of $38.08 in early October. However, I believe the clarity we provided to the market on our capital allocation and funding plans, assisted by positive macro factors, contributed to a turnaround, with our share price ending 2018 at $43.71.

Yet despite the turnaround, Emera's absolute share price and TSR performance for the full year was negative. Equity capital market conditions were challenging across most sectors and for almost all companies in our sector. It is notable, however, that on a relative basis, Emera's performance in the market was strong. For the year, we outperformed the TSX Capped Utilities Index, including all but three companies within the index. We also outperformed the broader TSX Composite Index and the S&P 500 in 2018. Over the last five years, we have similarly outperformed the TSX and Utilities Indexes.

DELIVERING GROWTH

We're excited about the $6.5 billion in growth opportunities we have in front of us over the next three years, focused on investments in renewable and clean energy, the modernization of aging infrastructure, and customer-focused technologies. To deliver this growth, last year we shared details of our funding plan outlining our increased focus on internal sources of funding instead of raising large amounts of new equity from the market, strengthening our balance sheet and making us more independent of variable market conditions.

In August, we adjusted our dividend growth target to 4–5 per cent through to 2021. We see this level of growth as both competitive and more sustainable, allowing us to reinvest more in our business while still delivering long-term value for shareholders.

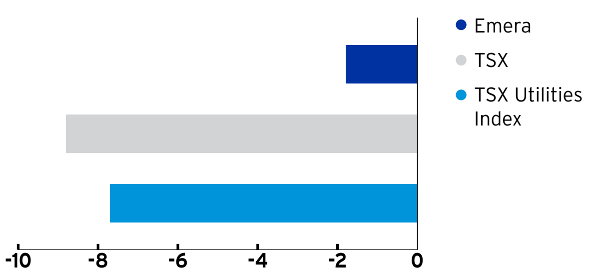
In 2018, we also began our work on optimizing our portfolio to best position us for future growth. In November, we announced the sale of our natural gas generating facilities in New England for $590 million USD. We are advancing our portfolio evaluation, and we expect this work to be complete by the end of 2019.

DELIVERING FOR OUR CUSTOMERS

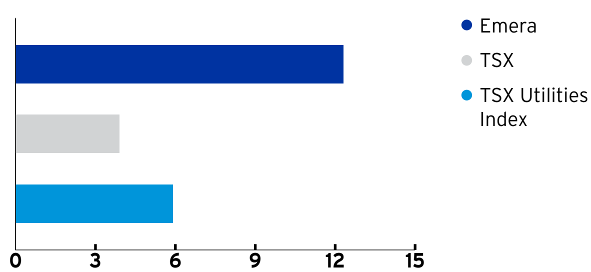
The energy industry continued to change at an unprecedented rate with shifting customer expectations, increasingly complex regulatory environments and continued demand for cleaner, affordable and reliable energy.

In 2018, we completed construction on two large solar projects, totalling 145MW, at Tampa Electric. This is part of an $850 million USD investment to install 600MW of new solar generation in Florida. In the first few months of 2019, over 2.3 million solar panels were installed over multiple

Total Shareholder Return



Five Year Annualized Total Shareholder Return
(2014–2018)



sites, representing an additional 230MW placed into service. Once this phase of our solar program is complete, seven per cent of Tampa Electric's energy generation will come from the sun – a tremendous shift to cleaner energy for customers in Florida.

The modernization of the Big Bend facility is another key part of our transformation work at Tampa Electric. This $850 million USD investment will increase efficiency and reduce emissions by upgrading one coal unit to high efficiency natural gas generation and retiring a second unit early. This project will save customers $750 million USD on a net present value basis, reduce carbon intensity and improve the safety of this 50-year-old facility. The modernized plant will also provide a reliable source of baseload energy that can support even more solar development, contributing to a cleaner energy future.

The Maritime Link was placed into service in 2018. This important mega-project enables energy flow between Newfoundland and Labrador and mainland North America for the first time in history and creates a new energy loop in Atlantic Canada. We are proud of this project that fundamentally changes the future of energy in the region and beyond.

We also made good progress on our $500 million investment to deploy more than 1.5 million smart meters across our utilities in the next five years – giving our customers greater access to real-time energy use data and providing even more customer control and choice.

We have great confidence that these big initiatives are sound investments that will generate reliable returns and ensure Emera remains a leader in our evolving industry. But we also recognize that technology, customer trends and regulatory sentiments are shifting and evolving. And while we cannot predict with 20/20 clarity the outcomes of these changes, I am confident that we have the right innovation stance and the right portfolio of businesses for future growth. We are taking the right steps to review and adjust our strategy, to test new technologies and approaches and to position ourselves to continue to be ready to identify and seize the right solutions for our business.

A STRONG TEAM DELIVERING OPERATIONAL EXCELLENCE

It's the commitment, expertise and hard work of our team right across the business that enables us to grow and deliver results.

Safety is our number one priority. In 2018, we made measurable progress on our journey to world-class safety by implementing a new Safety Management Program across Emera's operating companies. Our reinforced commitment is reflected in better year-over-year safety performance. We improved our governance and our safety systems, and we further strengthened our *speak up* culture. But we know we still have work to do. We remain steadfast in our focus on becoming an Emera where no one gets hurt.

We continued our focus on being an employer of choice, attracting and retaining the best employees to deliver on our strategy. In 2018, we invested in new tools for our team, including Leadership Competencies and improved employee communications. Emera is proud to be recognized as one of Canada's Best Employers by *Forbes* magazine and one of Canada's Top 100 Employers in 2019.

Sustainability is core to everything we do. In 2018, we continued to make energy cleaner, to build stronger communities and to respect the environment. Our strategy to reduce carbon intensity is a key part of our sustainability commitment, and our progress on carbon reduction is significant. While the nature of our industry and the history of the generation mix in the regions where we operate mean we do have some high-carbon-emitting infrastructure today, Emera is one of the companies making a difference in the reduction of carbon emissions, as we continue to execute on our strategy. In this light, we are proud to be named one of Canada's Best 50 Corporate Citizens in 2018 by Corporate Knights for our sustainability commitments and results.

I would like to thank our Chair, Jackie Sheppard, and the entire Board for their insight and guidance. I appreciate their ongoing leadership and support, especially in such a significant year of transition for our company.

Clearly, 2018 was both a challenging and successful year for Emera. In the face of it all, our team stayed focused and did what we do best – work safely, execute with discipline and innovate for new opportunities and solutions. I'm incredibly proud and grateful to lead our dedicated team during this exciting time for our company and our industry.

Scott Balfour
President and Chief Executive Officer, Emera

FINANCIAL REVIEW

MANAGEMENT'S DISCUSSION & ANALYSIS

As at February 15, 2019

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 2018 relative to the same quarter in 2017; the full year of 2018 relative to 2017 and selected financial information for 2016; and its financial position as at December 31, 2018 relative to December 31, 2017. 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 currently carried out through six business segments: Emera Florida and New Mexico, Nova Scotia Power Inc., Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other. The Company is reviewing its internal reporting to the chief operating decision maker and considering changes to its reportable segments for 2019.

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, 2018. 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
SeaCoast Gas Transmission, LLC ("SeaCoast")	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 ("FTC")
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 Investments	
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 ("NLPUB")
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 that could cause results or events to differ from current expectations are discussed in the "Business Overview and 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; liquidity and capital market risk; market for, pricing and timing of select asset sales; future dividend growth; timing and costs associated with certain capital investment; 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; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty 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

Based in Halifax, Nova Scotia, Emera owns and operates cost-of-service rate-regulated electric and gas utilities in Canada, the United States and the Caribbean. Cost-of-service utilities provide essential gas and electric services in designated territories under franchises, and are overseen by regulatory authorities. Emera's strategic focus is to safely deliver cleaner, affordable and reliable energy to its customers.

Approximately 70 per cent of Emera's current adjusted earnings are generated from operations in Florida and Nova Scotia. These jurisdictions provide generally stable regulatory and strong economic environments. Approximately 50 per cent of Emera's assets and current adjusted earnings are from its operations in Florida.

Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), the amount of equity in the capital structure and the return on equity as allowed through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera has a $6.5 billion capital investment plan over the 2019 to 2021 period, including investing $2.2 billion ($1.7 billion USD) in Florida for Tampa Electric's 600 megawatts ("MW") of new solar generation and the modernization of the Big Bend Power Station. This planned capital investment will be funded primarily through internally generated cash flows, debt raised at the operating company level and select asset sales. Equity capital markets, including the issuance of common and preferred equity and the dividend reinvestment plan will continue to support the company's future capital investments. Maintaining investment-grade credit ratings is a key priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2021. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time.

Seasonal patterns and other weather events affect demand and operating costs. Similarly, mark-to-market adjustments and foreign currency exchange can have a material impact on financial results for a specific period. Emera's consolidated net income and cash flows are also impacted by movements in the US dollar relative to the Canadian dollar and benefits from a weaker Canadian dollar. Emera generally hedges transactional exposure (but does not hedge translational exposure). These impacts, as well as the timing of capital investment and other factors mean that results in any one quarter are not necessarily indicative of results in any other quarter or for the year as a whole.

Energy markets worldwide are facing unprecedented change and Emera is well positioned to respond to shifting customer demands, complex regulatory environments and the trend towards de-carbonization. Renewable generation and battery storage are getting both more affordable and efficient. Customers are looking for more choice, control and reliability. Climate change and extreme weather are shaping how utilities operate and how they invest in infrastructure. There is also an overall need to replace aging infrastructure. Emera sees opportunity in these changes. Emera's efforts to fund investments in renewable and technology assets with related fuel or operating cost savings balances the opportunity with managing rate pressure and affordability for customers.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the recently completed Maritime Link in Atlantic Canada, the ongoing construction of new solar generation at Tampa Electric, and the modernization of the Big Bend Power Station at Tampa Electric. All of these projects demonstrate Emera's strategy of finding cleaner ways to meet the energy needs of customers while keeping rates affordable.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships with regulators, stakeholders and the communities where we operate.

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. These measures are discussed and reconciled below.

Adjusted Net Income

Emera calculates an adjusted net income measure by excluding the effect of mark-to-market ("MTM") adjustments and the impact in 2017 of US tax reform, signed into law on December 22, 2017 in the *US Tax Cuts and Jobs Act of 2017* ("the Act").

The MTM adjustments are a result of the following:

- 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 Power Company LLC ("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 related to equity securities held in Emera Caribbean and Corporate and Other.

Management believes excluding from net 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 ongoing operations of the business, and allows investors to better understand and evaluate the business. Management and the Board of Directors exclude these mark-to-market adjustments for evaluation of performance and incentive compensation.

In Q4 2017, the Company recorded a non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. The revaluation of an existing asset is not the result of any operational or market driven event. Management therefore believes excluding from net income the effect of this revaluation better distinguishes ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Emera Energy, Emera Caribbean and Corporate and Other, for further details on mark-to-market adjustments.

The following reconciles reported net income attributable to common shareholders, to adjusted net income attributable to common shareholders; and reported earnings per common share – basic, to adjusted earnings per common share – basic:

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2018	2017	**2018**	2017	2016
Net income (loss) attributable to common shareholders	**$ 231**	$ (228)	**$ 710**	$ 266	$ 227
Revaluation of US non-regulated deferred income taxes	**$ –**	$ (317)	**$ –**	$ (317)	$ –
After-tax mark-to-market gain (loss)	**$ 64**	$ (48)	**$ 39**	$ 59	$ (248)
Adjusted net income attributable to common shareholders	**$ 167**	$ 137	**$ 671**	$ 524	$ 475
Earnings per common share – basic	**$ 0.98**	$ (1.06)	**$ 3.05**	$ 1.25	$ 1.33
Adjusted earnings per common share – basic	**$ 0.71**	$ 0.64	**$ 2.88**	$ 2.46	$ 2.77

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 in assessing Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital 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.

The Company's EBITDA and Adjusted EBITDA may not be comparable to EBITDA measures of other companies but, in management's view, appropriately reflect Emera's specific operating performance. 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.

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

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2018	2017	**2018**	2017	2016
Net income (loss) [1]	**$ 231**	$ (232)	**$ 747**	$ 299	$ 266
Interest expense, net	**186**	175	**713**	698	585
Income tax expense (recovery)	**40**	329	**69**	520	(22)
Depreciation and amortization	**229**	212	**916**	856	588
EBITDA	**686**	484	**2,445**	2,373	1,417
Mark-to-market gain (loss), excluding income tax and interest	**94**	(75)	**58**	78	(327)
Adjusted EBITDA	**$ 592**	$ 559	**$ 2,387**	$ 2,295	$ 1,744

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

CONSOLIDATED FINANCIAL REVIEW

SIGNIFICANT ITEMS AFFECTING EARNINGS

Earnings Impact of After-Tax Mark-to-Market Gains and Losses

After-tax mark-to-market increased $112 million to a $64 million gain in Q4 2018, compared to a $48 million loss in Q4 2017, mainly due to changes in Emera Energy's existing contract positions. For the year ended December 31, 2018, after-tax mark-to-market gains decreased $20 million to $39 million, compared to $59 million in 2017. This decrease, primarily related to Emera Energy, was due to a larger reversal of mark-to-market losses in Q1 2017 and changes in existing contract positions, partially offset by lower amortization of gas transportation assets in 2018.

Florida State Tax Apportionment

In Q3 2018, Emera received approval from the Florida Department of Economic Opportunity to change its Florida state tax apportionment factors. This change resulted in the Company recording a tax benefit of approximately $23 million, or $0.10 per common share, as a result of the remeasurement of certain deferred tax balances.

US Tax Reform

On December 22, 2017, the *Tax Cuts and Jobs Act of 2017* was signed into law. As a result, in Q4 2017, the Company was required to revalue its US deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company recognized a $317 million income tax expense in 2017 as a result of the provisional revaluation of its US non-regulated net deferred income tax assets. There was no impact to earnings on the revaluation of the utilities' net deferred tax liabilities as the Act allowed for an offsetting regulatory liability.

No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. The measurement period allowed by SEC Staff Accounting Bulletin 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* ("SAB 118") is now closed.

On November 26, 2018, the Internal Revenue Service ("IRS") issued proposed regulations on the interest deductibility limitation rules legislated under the Act. The Company believes its US based financing interest will be deductible under the Act.

Emera's effective tax rate for 2018 was 8 per cent. Absent the reduction of the US federal corporate income tax rate, the effective tax rate would have been 13 per cent. For further details on the effective tax rate, refer to note 7 to the consolidated financial statements for the year ended December 31, 2018.

CONSOLIDATED FINANCIAL HIGHLIGHTS BY BUSINESS SEGMENT

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
Adjusted Net Income	**2018**	2017	**2018**	2017	2016
Emera Florida and New Mexico	**$ 101**	$ 80	**$ 428**	$ 382	$ 172
NSPI	**28**	23	**131**	129	130
Emera Maine	**11**	8	**44**	46	47
Emera Caribbean	**14**	1	**45**	31	100
Emera Energy	**44**	26	**120**	24	24
Corporate and Other	**(31)**	(1)	**(97)**	(88)	2
Adjusted net income attributable to common shareholders	**$ 167**	$ 137	**$ 671**	$ 524	$ 475
Revaluation of US non-regulated deferred income taxes	**–**	(317)	**–**	(317)	–
After-tax mark-to-market gain (loss)	**64**	(48)	**39**	59	(248)
Net income (loss) attributable to common shareholders	**$ 231**	$ (228)	**$ 710**	$ 266	$ 227

The following table highlights the significant changes in adjusted net income from 2017 to 2018:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2017	**$ 137**	**$ 524**
Emera Energy	18	96
Emera Florida and New Mexico	21	46
Emera Caribbean	13	14
NSPML and LIL equity earnings	(4)	14
Florida state tax apportionment	–	23
Other	(18)	(46)
Adjusted net income – 2018	**$ 167**	**$ 671**

Refer to the segment "Financial Highlights" section for further details of business unit contributions.

For the millions of Canadian dollars			Year ended December 31
	2018	2017	2016
Operating cash flow before changes in working capital	**$ 1,806**	$ 1,297	$ 919
Change in working capital	**(116)**	(104)	134
Operating cash flow	**$ 1,690**	$ 1,193	$ 1,053
Investing cash flow	**$ (2,190)**	$ (1,761)	$ (9,037)
Financing cash flow	**$ 344**	$ 593	$ 7,448

As at millions of Canadian dollars			December 31
	2018	2017	2016
Total assets	**$ 32,314**	$ 28,806	$ 29,271
Total long-term debt (including current portion)	**$ 15,411**	$ 13,881	$ 14,744

Refer to the "Consolidated Cash Flow Highlights" section for further discussion of cash flow.

CONSOLIDATED INCOME STATEMENT HIGHLIGHTS

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Variance	Year ended December 31		Variance	Year ended December 31
	2018	2017		**2018**	2017		2016
Operating revenues	**$ 1,799**	$ 1,473	$ 326	**$ 6,524**	$ 6,226	$ 298	$ 4,277
Operating expenses	**1,368**	1,231	(137)	**5,126**	4,808	(318)	3,722
Income from operations	**431**	242	189	**1,398**	1,418	(20)	555
Income from equity investments	**33**	34	(1)	**154**	124	30	100
Other income (expenses)	**(7)**	(4)	(3)	**(23)**	(25)	2	174
Interest expense, net	**186**	175	(11)	**713**	698	(15)	585
Income tax expense (recovery)	**40**	329	289	**69**	520	451	(22)
Net income (loss)	**231**	(232)	463	**747**	299	448	266
Net income (loss) attributable to common shareholders	**231**	(228)	459	**710**	266	444	227
Revaluation of US non-regulated deferred income taxes	**–**	(317)	317	**–**	(317)	317	–
After-tax mark-to-market gain (loss)	**64**	(48)	112	**39**	59	(20)	(248)
Adjusted net income attributable to common shareholders	**$ 167**	$ 137	$ 30	**$ 671**	$ 524	$ 147	$ 475
Earnings per common share – basic	**$ 0.98**	$ (1.06)	$ 2.04	**$ 3.05**	$ 1.25	$ 1.80	$ 1.33
Earnings per common share – diluted	**$ 0.98**	$ (1.06)	$ 2.04	**$ 3.04**	$ 1.24	$ 1.80	$ 1.32
Adjusted earnings per common share – basic	**$ 0.71**	$ 0.64	$ 0.07	**$ 2.88**	$ 2.46	$ 0.42	$ 2.77
Dividends per common share declared	**$ –**	$ –	$ –	**$ 2.2825**	$ 2.1325	$ 0.1500	$ 1.9950
Adjusted EBITDA	**$ 592**	$ 559	$ 33	**$ 2,387**	$ 2,295	$ 92	$ 1,744

Operating Revenues

For the fourth quarter of 2018, operating revenues increased $326 million, compared to the fourth quarter of 2017. Absent increased mark-to-market gains of $174 million, operating revenues increased $152 million due to:

- $79 million increase at Emera Florida and New Mexico due to the impact of a stronger USD, higher electric sales volumes due to customer growth, weather and rates related to completed solar projects at Tampa Electric;
- $30 million increase at NSPI as a result of increased sales volumes due to load growth and weather;
- $35 million increase at Emera Energy reflecting significant pipeline maintenance that reduced marketing and trading margins on hedged capacity in Q4 2017 and higher capacity prices for its New England Gas Generation ("NEGG") fleet in Q4 2018.

Operating revenues increased $298 million for the year ended December 31, 2018, compared to 2017. Absent decreased mark-to-market gains of $22 million, operating revenues increased $320 million due to:

- $126 million increase at NEGG reflecting higher capacity prices and more favourable market conditions in 2018, and an unplanned outage at the Bridgeport facility in 2017;
- $102 million increase at NSPI as a result of increased sales volumes due to load growth and weather, the 2017 refund to customers of 2016 over-recovery of fuel costs, and increased fuel-related electricity pricing, partially offset by the impact of the Maritime Link assessment;
- $71 million increase in marketing and trading margin at Emera Energy Services ("EES"), driven primarily by the impact of cold weather in Q1 2018, warm weather in Q3 2018 and significant pipeline maintenance that reduced margins on hedged capacity in Q4 2017;

- $52 million increase at Emera Florida and New Mexico as a result of higher clause recoveries and favourable customer growth in PGS and favourable weather in Florida and New Mexico, higher electric sales volumes due to weather and higher base rates related to solar projects and the Polk Power Station expansion at Tampa Electric. These increases were partially offset by lower commodity costs in New Mexico; and
- $26 million decrease at Bayside Power due to lower electricity sales reflecting renegotiation of the Bayside Power power purchase agreement ("PPA").

Operating Expenses

For the fourth quarter of 2018, operating expenses increased $137 million, compared to the fourth quarter of 2017. Absent decreased mark-to-market gains of $3 million, operating expenses increased $134 million due to:

- $90 million increase at Emera Florida and New Mexico as a result of increased operating, maintenance and general ("OM&G") at Tampa Electric resulting from the regulatory agreement to net storm costs and the 2018 tax reform benefits, and the impact of a stronger USD;
- $22 million increase at Corporate and Other mainly due to higher performance based compensation accruals; and
- $14 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and increased commodity prices, increased OM&G due to higher storm costs, partially offset by decreased fuel adjustment mechanism ("FAM") and fixed cost deferrals.

Operating expenses increased $318 million for the year ended December 31, 2018, compared to 2017. Absent increased mark-to-market gains of $6 million, operating expenses increased $324 million due to:

- $175 million increase at Emera Florida and New Mexico as a result of increased OM&G at Tampa Electric from the regulatory agreement to net storm costs and the 2018 tax reform benefits;
- $88 million increase at NSPI due to increased fuel costs as a result of payment of the Maritime Link assessment and increased commodity pricing, partially offset by decreased FAM and fixed cost deferrals;
- $60 million increase at NEGG due to an increase in generation volumes in 2018 reflecting the impact of the unplanned outage at Bridgeport Energy in 2017 and more favourable market conditions in 2018;
- $56 million increase in depreciation and amortization due to normal asset growth across the business; and
- $26 million decrease at Bayside Power due to decreased natural gas purchases reflecting renegotiation of the Bayside Power PPA.

Income from Equity Investments

Income from equity investments increased $30 million for the year ended December 31, 2018, compared to 2017, due to increased capacity prices at Bear Swamp and higher equity earnings from NSPML and LIL.

Income Tax Expense

The decrease in income tax expense for the fourth quarter of 2018, compared to the same period in 2017, was due to the reduction of the US federal corporate income tax rate, partially offset by increased income before provision for income taxes. The reduction of the US federal corporate income tax rate resulted in a $339 million decrease in income tax expense for the quarter, including the $317 million income tax expense recognized in Q4 2017 related to the revaluation of the Company's US non-regulated net deferred income tax assets at the new tax rate.

The decrease in income tax expense for the year ended December 31, 2018, compared to 2017, was due to the reduction of the US federal corporate income tax rate, amortization of deferred tax regulatory liabilities in the US utilities and remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors. The reduction of the US federal corporate income tax rate resulted in a $405 million decrease in income tax expense for the year ended December 31, 2018, including the $317 million income tax expense recognized in 2017 related to the revaluation of the Company's US non-regulated net deferred income tax assets at the new tax rate.

As a result of the *US Tax Cuts and Jobs Act of 2017*, the US federal corporate income tax rate was reduced from 35 per cent to 21 per cent. This reduction resulted in a significant decrease in income tax expense, as described above, however the net impact to earnings was minimal. This was a result of the favourable impact of the reduced tax rate on Emera Energy earnings which was offset by the unfavourable impact of reduced tax recovery on losses arising from Corporate borrowing costs. The net impact on US based regulated utilities earnings was immaterial. Tax benefits from the reduced rates in Tampa Electric were netted against deferred storm costs for 2018. Tax benefits deferred by PGS were netted against the amortization of its manufactured gas plant ("MGP") environmental regulatory asset in 2018. Tampa Electric and PGS tax benefits will be adjusted in rates starting in 2019. As of December 31, 2018, NMGC recorded a regulatory liability of $8 million USD, to reflect 2018 tax reform benefits, which are being addressed through ongoing rate case proceedings. Certain of the tax benefits for Emera Maine are reflected in rates effective July 1, 2018 with other components being deferred to be addressed in future regulatory proceedings.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the fourth quarter in 2018, net income attributable to common shareholders was favourably impacted by the $317 million 2017 revaluation of US non-regulated deferred income taxes and the $112 million increase in after-tax mark-to-market gains primarily related to Emera Energy. Absent the 2017 revaluation of US non-regulated deferred income taxes and favourable mark-to-market changes, adjusted net income attributable to common shareholders increased $30 million due to higher contributions from Emera Energy and Emera Florida and New Mexico, partially offset by decreased contributions from Corporate and Other.

For the year ended December 31, 2018 net income attributable to common shareholders was favourably impacted by the $317 million 2017 revaluation of US non-regulated deferred income taxes, partially offset by the $20 million decrease in after-tax mark-to-market gains primarily related to Emera Energy. Absent the 2017 revaluation of US non-regulated deferred income taxes and unfavourable mark-to-market changes, adjusted net income attributable to common shareholders increased $147 million. The increase was due to higher contributions from Emera Energy, Emera Florida and New Mexico and NSPML and LIL, and the tax benefit recorded as a result of remeasurement of certain deferred tax balances due to the change in Florida state tax apportionment factors, partially offset by decreased contributions from Corporate and Other.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic were higher for the fourth quarter and for the year ended December 31, 2018 due to the results of the revaluation of US non-regulated deferred income taxes in 2017 and higher earnings in 2018, partially offset by the impact of the increase in the weighted average number of common shares outstanding reflecting the issuance of shares in December 2017.

Adjusted earnings per common share – basic were higher for the fourth quarter and for the year ended December 31, 2018 due to higher adjusted earnings, partially offset by the increase in the weighted average of common shares outstanding.

Effect of Foreign Currency Translation

Emera operates internationally, including in Canada, the US and various Caribbean countries. As such, the Company generates revenues and incurs expenses denominated in local currencies which are translated into Canadian dollars for financial reporting. Changes in translation rates, particularly in the value of the US dollar against the Canadian dollar, can positively or adversely affect results.

Earnings from Emera's foreign operations are translated into Canadian dollars. In general, Emera's earnings benefit from a weakening Canadian dollar and are adversely impacted by a strengthening Canadian dollar. The impact of foreign exchange in any period is driven by rate changes, the timing of earnings from foreign operations during the period, and the percentage of earnings from foreign operations in the period.

Results of operations from foreign operations are translated at the weighted average rate of exchange and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates for 2018 and 2017 are as follows:

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Weighted average CAD/USD exchange rate	**$ 1.32**	$ 1.27	**$ 1.30**	$ 1.30
Period end CAD/USD exchange rate	**$ 1.36**	$ 1.25	**$ 1.36**	$ 1.25

The weakening of the CAD increased earnings by $9 million and adjusted earnings by $7 million in Q4 2018 compared to Q4 2017. The weakening of the CAD increased earnings by $1 million and adjusted earnings by $4 million in 2018, compared to 2017.

Consistent with the Company's risk management policies, Emera partially 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.

The table below includes Emera's significant segments whose contributions to adjusted earnings are recorded in US dollar currency.

millions of US dollars	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Emera Florida and New Mexico	**$ 77**	$ 63	**$ 331**	$ 295
Emera Maine	**9**	7	**34**	36
Emera Caribbean	**11**	1	**35**	24
Emera Energy (1)	**35**	19	**100**	21
	132	90	**500**	376
Corporate and Other (2)	**(33)**	(29)	**(130)**	(116)
Total (3)	**$ 99**	$ 61	**$ 370**	$ 260

(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.
(3) Amounts above do not include the impact of mark-to-market or US tax reform.

BUSINESS OVERVIEW AND OUTLOOK

Earnings from Emera's regulated utilities are most directly impacted by the rate of return on equity ("ROE") or rate base and capital structure approved by their regulators, the prudent management of operating costs, the approved recovery of regulatory deferrals, energy sales volumes including the impact of weather, and the timing and amount of capital expenditures. Electric and gas sales volumes are primarily driven by general economic conditions, population and weather. Emera's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. The electric and gas utilities' industrial customers include manufacturing facilities and other large volume operations.

EMERA FLORIDA AND NEW MEXICO

Emera Florida and New Mexico includes TECO Energy, the parent company of TEC, NMGC, SeaCoast and TECO Finance. TEC 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, and PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida. NMGC is a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a regulated intrastate natural gas transmission company offering services in Florida.

Tampa Electric

With approximately $7.8 billion USD of assets and approximately 764,000 customers at December 31, 2018, Tampa Electric owns 5,238 MW of generating capacity, of which 77 per cent is natural gas-fired, 20 per cent is coal and petroleum coke ("petcoke") and 3 per cent is solar. Tampa Electric owns 2,150 kilometres of transmission facilities and 18,750 kilometres of distribution facilities.

Tampa Electric's approved regulated ROE range is 9.25 per cent to 11.25 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 10.25 per cent is used for the calculation of the return on investments for clauses.

Peoples Gas System

With approximately $1.4 billion USD of assets and approximately 392,000 customers, the PGS system includes approximately 20,920 kilometres of natural gas mains and 11,910 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2.0 billion therms in 2018.

The approved ROE range for PGS is 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. Absent any rate case filing, the bottom of the range will increase to 9.75 per cent in 2021. An ROE of 10.75 per cent is used for the calculation of return on investments for clauses.

New Mexico Gas Company, Inc.

With over $1.3 billion USD of assets and approximately 530,000 customers, NMGC serves approximately 60 per cent of the state's population in 23 of New Mexico's 33 counties. NMGC's system includes approximately 2,640 kilometres of transmission lines and 17,040 kilometres of distribution lines. Annual natural gas throughput was approximately 825 million therms in 2018.

The approved ROE for NMGC is 10 per cent, on an allowed equity capital structure of 52 per cent. NMGC's rates were established in a 2012 rate case settlement and were frozen until December 31, 2017 per the June 2016 NMPRC order (the "Order") approving Emera's acquisition of TECO Energy. NMGC filed a rate case, including the prospective impact of tax reform, on February 26, 2018. A hearing in the rate case was held September 24, 2018, when an uncontested stipulation on the rate request was presented. A second hearing in the rate case, related to 2018 tax reform benefits, was held December 17, 2018. Decisions by the NMPRC on the rate case and on 2018 tax reform benefits are expected in 2019.

Emera Florida and New Mexico Outlook

The Florida utilities anticipate earning within their allowed ROE ranges in 2019 and expect rate base and earnings to be higher than prior years. Tampa Electric expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida. Assuming normal weather in 2019, Tampa Electric sales volumes are expected to be consistent with 2018 sales volumes which benefited from favourable weather. PGS expects customer growth rates in 2019 to be consistent with 2018, reflective of economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. Assuming normal weather in 2019, PGS sales volumes are expected to increase at a level lower than customer growth as 2018 energy sales benefited from favourable weather.

In September 2018, Tampa Electric announced its intention to invest approximately $235 million USD during 2018 through 2022 for its advanced metering infrastructure ("AMI") project.

In May 2018, Tampa Electric announced its intention to invest approximately $850 million USD during 2018 through 2023 to modernize the Big Bend Power Station. Refer to the "Developments" section for further details.

In September 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new utility-scale solar photovoltaic projects across its service territory. On November 6, 2017, the FPSC approved a settlement agreement allowing a solar base rate adjustment ("SoBRA") that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects phased in from late 2018 through early 2021. On May 8, 2018, the FPSC approved Tampa Electric's first SoBRA. This SoBRA represents 145 MW and $24 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in September 2018. On October 29, 2018, the FPSC approved Tampa Electric's second SoBRA. This SoBRA represents 260 MW and $46 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in January 2019.

In September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs of approximately $102 million USD. The amount charged to the storm reserve exceeded the balance in the reserve by $47 million USD. On December 28, 2017, Tampa Electric petitioned the FPSC for recovery of estimated restoration costs in excess of the storm reserve for several named storms and to replenish the reserve to the $56 million USD level that existed as of October 31, 2013. On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric authorizing the utility to net the amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. In Q1 2018, Tampa Electric recorded OM&G expense and a regulatory liability of $19 million USD to offset tax reform benefits. This deferral was amortized over the balance of the year as a credit against recognition of storm expense. In total, OM&G expense due to the allowed netting of the storm cost recovery with tax reform benefits, net of amortization of first quarter tax reform benefits, was approximately $22 million USD for Q4 2018 and $103 million USD for the year ended December 31, 2018.

Tampa Electric's final storm costs subject to netting will be determined in a separate regulatory proceeding in 2019. Any difference will be trued up and returned to customers in 2020. On August 20, 2018, the FPSC approved a reduction in base rates of $103 million USD annually beginning in 2019 to reflect the impact of tax reform.

On September 12, 2018, the FPSC approved a settlement agreement filed by PGS, authorizing the utility to amortize $11 million USD of its MGP environmental regulatory asset and net it against its estimated 2018 tax reform benefits. Beginning in January 2019, PGS lowered base rates by $12 million USD to reflect the impact of tax reform and reduced depreciation rates by $10 million USD, in accordance with the settlement agreement.

NMGC expects 2019 earnings and rate base to be higher than prior years. Customer growth rates are expected to be consistent with 2018, reflecting expectations for housing starts and new connections.

In 2019, Emera Florida and New Mexico expects to invest approximately $1.3 billion USD in capital projects, including allowance for funds used during construction ("AFUDC"), compared to $1.2 billion USD in 2018. Capital projects include supporting normal system reliability and growth at the three utilities. Tampa Electric's investments include the modernization of the Big Bend Power Station, solar projects and AMI. AFUDC will be earned during the construction periods.

PGS will make investments in 2019 to expand its system and support customer growth, including expected investments related to compressed natural gas fueling stations and liquefied natural gas facilities, and continued replacement of obsolete plastic, cast iron and bare steel pipe.

On April 4, 2018, SeaCoast executed an agreement with Seminole Electric Cooperative, Inc. ("Seminole") to provide long-term firm gas transportation service to Seminole's new gas-fired generating facility being constructed in Putnam County, Florida. SeaCoast will construct and operate a 21-mile, 30-inch pipeline lateral that is anticipated to go into service by 2022. The estimated capital investment is projected to be in the range of $100 million to $120 million USD with the majority of the investment expected in 2020 and 2021.

NMGC will complete planning phases of the Santa Fe Mainline Looping project in 2019, and will continue to invest in system improvements by replacing legacy pipe and making pipeline integrity management improvements.

NSPI

NSPI is a vertically integrated regulated electric utility. It is the primary electricity supplier in Nova Scotia, Canada. NSPI has approximately $5.1 billion of assets and provides electricity generation, transmission and distribution services to approximately 519,000 customers. The Company owns 2,441 MW of generating capacity, of which approximately 43 per cent is coal-fired; 28 per cent is natural gas and/or oil; 20 per cent is hydro and wind; 7 per cent is petcoke and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 546 MW of capacity. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

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 anticipates earning within its allowed ROE range in 2019 and expects modest rate base growth which will deliver a similar modest increase in earnings.

In December 2015, the *Electricity Plan Implementation (2015) Act* ("*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. NSPI is currently operating under a Rate Stability Plan for fuel costs for 2017 through 2019 which includes an average annual rate increase of 1.5 per cent for each of these three years.

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 investments have been made in renewable generation and system reliability projects.

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. NSPI continues to work with both levels of government to comply with these regulations, maximizing efficiency of emission control measures and minimizing customer cost. NSPI anticipates that any costs prudently incurred to achieve the legislated reductions will be recoverable from customers under NSPI's regulatory framework.

The Government of Canada ("the Government") introduced the Pan-Canadian Framework on Clean Growth and Climate Change ("the Framework") in early 2017. As part of the Framework, in February 2018, the Government introduced proposed changes to the greenhouse gas ("GHG") coal regulations designed to remove coal fired generation by 2030, subject to equivalency agreements. At that time, a regulation was introduced specifying the emission intensities required for new natural gas fired generation and for boiler conversions from coal to natural gas. The Government published final regulations for both coal and natural gas generation in December 2018. NSPI expects the changes to equivalency agreements to be finalized in 2019. This agreement allows NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent. Beginning January 1, 2019, each province and territory in Canada is required to have a carbon pricing system which meets a benchmark set by the Government. On October 23, 2018, the Government of Canada confirmed that the cap and trade carbon pricing system proposed by the Government of Nova Scotia met the federal benchmark. The Government of Nova Scotia has published final details on the program regarding registration and operating rules. NSPI was granted 22 million metric tons of carbon dioxide allowances for the four year compliance period of 2019 through 2022. The Government of Canada is continuing to develop a clean fuel standard with the expectation that it will not apply to the electricity sector until 2022 at the earliest. NSPI anticipates any prudently incurred costs required to comply with the Framework, and the cap and trade pricing system, will be recoverable from customers.

In November 2018, the Government of Canada presented the 2018 Federal Fall Economic Statement ("the Statement"). The Statement introduced proposed legislation that will provide for the immediate expensing of 100 per cent of the cost of specified clean energy equipment and increased first-year tax depreciation for eligible property. Once enacted, these measures will apply to eligible property that is acquired after November 20, 2018 and available for use before 2028. These measures will impact the timing of tax deductions related to NSPI's investment in property, plant and equipment.

In June 2018, the UARB approved NSPI's $133 million capital application to upgrade customers to AMI. NSPI will commence installation of AMI in 2019 and expects the full AMI project to be completed in 2021.

In 2019, NSPI expects to invest approximately $340 million, including AFUDC, in capital projects, compared to $348 million in 2018. NSPI is investing in projects which will support system reliability and AMI.

EMERA MAINE

Emera Maine is a transmission and distribution ("T&D") regulated electric utility with assets of approximately $1.2 billion USD serving approximately 159,000 customers in the State of Maine. Emera Maine owns and operates approximately 2,000 kilometres of transmission facilities and 10,000 kilometres of distribution facilities. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through Emera Maine's T&D networks.

Approximately 44 per cent of Emera Maine's operating revenue represents distribution operations, 46 per cent is associated with transmission operations and 10 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

In June 2018, the MPUC approved a 5.3 per cent distribution rate increase. This increase was effective July 1, 2018 and is based on a 9.35 per cent ROE and a common equity component of 49 per cent. Prior to July 1, 2018, the allowed ROE was 9.0 per cent, on a common equity component of 49 per cent.

There are currently four pending complaints filed with the FERC to challenge the base ROE under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT"). On October 16, 2018, the FERC issued an order that addressed all four complaint proceedings. The FERC order proposed a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding was a 10.41 per cent base ROE for the ISO-NE OATT. The FERC has permitted parties to comment on the new methodology and its application to the four pending complaint proceedings. The current reserve is expected to be sufficient to cover the impact of this preliminary finding. For further discussion on the complaints, refer to note 26 to the consolidated financial statements for the year ended December 31, 2018.

Emera Maine's 2019 rate base is expected to grow modestly due to ongoing investment in transmission and distribution infrastructure, resulting in modest growth in earnings.

In 2019, Emera Maine expects to invest approximately $70 million USD (2018 – $76 million USD), primarily on transmission and distribution capital projects supporting normal system reliability.

EMERA CARIBBEAN

Emera Caribbean represents Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities including BLPC, a vertically integrated utility that is the sole provider of electricity in Barbados; GBPC, a vertically integrated utility that is the sole provider of electricity on Grand Bahama Island and a 51.9 per cent interest in Domlec, a vertically integrated utility on the island of Dominica. ECI also holds a 19.1 per cent indirect interest in Lucelec, a vertically integrated utility on the island of St. Lucia which is accounted for on the equity basis.

BLPC

With approximately $380 million USD of assets and approximately 130,000 customers, BLPC owns 249 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. BLPC owns approximately 168 kilometres of transmission facilities and 2,800 kilometres of distribution facilities. BLPC's approved regulated return on rate base is 10.0 per cent.

GBPC

With approximately $300 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. In December 2018, the GBPA approved GBPC's regulated return on rate base of 8.44 per cent for 2019. On January 15, 2018, Emera completed the acquisition of the common shares held by the minority shareholders of ICD Utilities Limited ("ICDU"), increasing the Company's interest in GBPC from 80.4 per cent to 100 per cent.

Domlec

Domlec serves approximately 26,000 customers. Domlec owns 27 MW of generating capacity of which 74 per cent is oil-fired and 26 per cent is hydro. Domlec owns approximately 452 kilometres of transmission facilities and 635 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

Emera Caribbean Outlook

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, more efficient and renewable energy generation and battery storage investments are being developed in the Caribbean.

In 2018, S&P issued several long- and short-term currency ratings changes and changes in ratings on certain bonds for Barbados. These ratings changes are not expected to have a material impact on BLPC.

On December 18, 2018, the Government of Barbados signed the *Income Tax Amendment Act* into law. The legislation, effective January 1, 2019, created a new corporate income tax rate schedule and eliminated certain tax credits. At the date of enactment, BLPC was required to remeasure its deferred income tax liability at its new lower corporate income tax rate, resulting in recognition of an income tax recovery, the majority of which was deferred as a regulatory liability. These changes had minimal impact on 2018 earnings and are expected to have minimal impact on future earnings.

Earnings from Emera Caribbean's utilities in 2019 are expected to be consistent with 2018.

Emera Caribbean plans to invest approximately $120 million USD in capital programs in 2019 (2018 – $68 million USD). This increase is due to investment in new, efficient oil based generation and renewable generation partially offset by lower spending at Domlec due to the completion of hurricane restoration in 2018.

EMERA ENERGY

Emera Energy includes 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; and an equity investment in a 50.0 per cent joint venture ownership of Bear Swamp, a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts. On November 26, 2018, Emera announced an agreement to sell its three New England Gas Generating facilities. The transaction is expected to close in the first quarter of 2019. Refer to the "Developments" section for further details.

Earnings from EES are 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. Under normal market conditions, the business is generally expected to deliver adjusted net earnings of $15 to $30 million USD ($45 to $70 million USD of margin), with the opportunity for upside when market conditions present.

Earnings from EEG's assets are largely dependent on market conditions, particularly the relative pricing of electricity and natural gas and the absolute price of natural gas as the marginal fuel in the supply stack, and capacity pricing in ISO-NE for NEGG. Efficient operations of the fleet to ensure unit availability, cost management, and effective commercial management are key success factors. Earnings from EEG will be lower in 2019 due to the pending sale of the NEGG facilities.

In 2019, Emera Energy expects to invest approximately $10 million (2018 – $34 million) in capital projects related to its generating assets to continue to improve reliability. This decrease is due to the expected sale of the NEGG facilities.

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, a 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, 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"), a utility services contractor primarily operating in Atlantic Canada.
- Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States.
- Emera US Finance LP, a wholly owned financing subsidiary of Emera.
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), holding Emera's non-consolidated investments in NSPML and LIL which are accounted for on the equity basis. These two transmission investments are related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador. See below for additional information on ENL.

Non-consolidated Investments Accounted for on the Equity Basis

- 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. This project completed commissioning and entered service on January 15, 2018.
- Emera's 49.5 per cent investment in the partnership capital of LIL, a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and the energization phase of the project began in June 2018. On June 27, 2018, Nalcor Energy recognized the first flow of energy from Labrador to Newfoundland and continues to work towards finalizing commissioning activities.
- Emera's 12.9 per cent investment in M&NP.

Corporate and Other includes corporate financing costs, earnings as a result of the equity investment in Maritime Link 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. The segment also includes corporate related costs that are dependent on the level of business development activity and acquisition-related initiatives.

Corporate and Other's costs are expected to be higher in 2019 due to lower intercompany revenue on intercompany financings as a result of the expected sale of NEGG facilities in Q1 2019; increased preferred dividend expense due to additional preferred shares issued in 2018; and lower tax recoveries due to the change in Florida state tax apportionment factors that resulted in the remeasurement of certain deferred tax balances in 2018.

Corporate and Other, excluding ENL as discussed below, expects to spend approximately $10 million on property, plant and equipment in 2019 (2018 – $41 million).

ENL

NSP Maritime Link Inc. ("NSPML")

Through its subsidiary, NSP Maritime Link Inc., ENL has invested, $1.8 billion of equity, debt and working capital, including $209 million of AFUDC, in development of the Maritime Link Project. Project to date, ENL has invested $545 million in equity, comprised of $452 million in equity contributed and $93 million of accumulated retained earnings, with the remaining being funded with working capital and debt. The project debt has been guaranteed by the Government of Canada.

The Maritime Link entered service on January 15, 2018 and provides for the transmission of energy as well as improved reliability and ancillary benefits, supporting the efficiency and reliability of both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill project is complete. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. All major contracts have been concluded.

Future equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. The approved ROE is 9 per cent.

In 2019, NSPML expects to invest approximately $20 million in capital related to construction close-out costs.

Labrador Island Link ("LIL")

ENL is a limited partner with Nalcor Energy in LIL, with total project costs currently estimated at $3.7 billion. Equity earnings are recorded based on an annual ROE of 8.5 per cent of the equity invested. The ROE is approved by the NLPUB.

Earnings from the LIL investment are based on the book value of the equity investment and the approved ROE. Emera's current equity investment is $534 million, and is forecasted to be $579 million by the end of 2019, comprised of $410 million in equity contribution and an estimated $169 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $600 million by 2020 when all Lower Churchill projects, including Muskrat Falls, are forecasted by Nalcor Energy to be placed in service.

Cash earnings and return of equity are forecasted by Nalcor Energy to begin in 2020 and until that point Emera will continue to record AFUDC earnings, with such earnings capitalized to its equity investment.

Equity earnings from NSPML and LIL are expected to be modestly higher in 2019 compared to 2018. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2017 and December 31, 2018 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$ (122)**	Decreased due to additions of property, plant, and equipment and payment of common dividend. These were partially offset by increased cash from operations, changes in borrowings and the issuance of preferred shares.
Inventory	**56**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and increased fuel inventory as a result of higher volumes and higher commodity pricing at NSPI.
Derivative instruments (current and long-term)	**(86)**	Decreased due to settlements of derivative instruments and lower commodity prices at NSPI.
Regulatory assets (current and long-term)	**158**	Increased due to the effect of a stronger USD on the translation of foreign subsidiaries, increased fuel clauses at Tampa Electric and increased deferred income tax regulatory asset at NSPI, partially offset by decreased storm reserve at Tampa Electric.
Assets held for sale (current and long-term), net of liabilities	**810**	Increased due to the pending sale of the NEGG facilities.
Property, plant and equipment, net of accumulated depreciation and amortization	**1,717**	Increased due to additions at regulated utilities, and the effect of a stronger USD on the translation of Emera's foreign subsidiaries, partially offset by the reclassification of NEGG facilities to assets held for sale and increased accumulated depreciation.
Investments subject to significant influence	**101**	Increased due to investment in LIL and NSPML.
Goodwill	**508**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Receivables and other assets (current and long-term)	**324**	Increased primarily due to reclassification of alternative minimum tax credit carryforwards from deferred income tax liabilities at Emera Florida and New Mexico and higher gas transportation assets at Emera Energy.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**1,475**	Increased due to the effect of a stronger USD on foreign currency debt, increased borrowings under existing credit facilities, and increased borrowings of long-term debt at Emera Florida and New Mexico.
Accounts payable	**128**	Increased due to the effect of a stronger USD on the translation of foreign subsidiaries and higher commodity volumes and prices at EES.
Deferred income tax liabilities, net of deferred income tax assets	**260**	Increased due to tax deductions in excess of accounting depreciation related to property, plant and equipment, reclassification of alternative minimum tax credit carryforwards to receivables and other current assets at Emera Florida and New Mexico, and net utilization of tax loss carryforwards, partially offset by increased income tax credits primarily related to solar projects at Tampa Electric.
Derivative instruments (current and long-term)	**55**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and new contracts at Emera Energy, partially offset by the reversal of 2017 asset management agreement mark-to-market losses.
Regulatory liabilities (current and long-term)	**142**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries and replenishment of the storm reserve at Tampa Electric, partially offset by increased deferrals related to derivative instruments at NSPI.
Pension and post-retirement liabilities	**82**	Increased due to a decrease in fair value of plan assets at Emera Florida and New Mexico and the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Other liabilities (current and long-term)	**155**	Increased due to investment tax credits primarily related to solar projects at Tampa Electric and the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Common stock	**215**	Increased due to the dividend reinvestment plan and issuance of common stock for the purchase of additional shares of ICDU.
Cumulative preferred stock	**295**	Increased due to the issuance of preferred shares.
Accumulated other comprehensive income	**503**	Increased due to the effect of a stronger USD on the translation of Emera's foreign subsidiaries.
Retained earnings	**184**	Increased due to net income in excess of dividends paid.
Non-controlling interest in subsidiaries	**(51)**	Decreased due to increased ownership in GBPC.

DEVELOPMENTS

Pending Sale of Emera Energy's New England Gas Generating Facilities

On November 26, 2018, Emera announced an agreement to sell its three NEGG facilities for $590 million USD plus a final working capital adjustment made on close. Proceeds from the sale of the NEGG facilities will be used to reduce corporate level debt and support capital investment opportunities within the regulated utility business. The transaction is expected to close in the first quarter of 2019 and is subject to certain regulatory approvals including approval of the FERC. The applicable provisions of the *Hart-Scott-Rodino Antitrust Act* have been satisfied.

Increase in Common Dividend

Effective August 9, 2018, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.26 to $2.35. The first quarterly dividend payment at the increased rate was paid on November 15, 2018.

USGAAP Reporting Extension

On January 26, 2018, Emera was granted exemptive relief by Canadian securities regulators allowing Emera to continue to report its financial results in accordance with USGAAP (the "Exemptive Relief"). On July 18, 2018, Emera was granted an order pursuant to the *Companies Act* (Nova Scotia) exempting Emera from the *Companies Act* requirement to prepare its annual financial statements in accordance with International Financial Reporting Standards ("IFRS") (the "Companies Act Relief"). Both the Exemptive Relief and the Companies Act Relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of the Company's financial year commencing after the Company ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities. The Exemptive Relief and the Companies Act Relief each replace similar exemptive relief that had been previously granted to Emera in 2014 and would have expired by January 1, 2019.

Preferred Shares

On May 31, 2018, Emera issued 12 million Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share at an initial dividend rate of 4.9 per cent. The aggregate gross and net proceeds from the offering were $300 million and $295 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes.

On July 6, 2018, Emera announced it would not redeem the 10,000,000 Cumulative Rate Reset First Preferred Shares, Series C Shares. The holders of the Series C Shares had the right, at their option, to convert all or any of their Series C Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series D of the Company on August 15, 2018 or to continue to hold their Series C Shares. On August 8, 2018, Emera announced that, after having taken into account all conversion notices received from holders, no First Preferred Shares, Series C Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series D Shares.

Tampa Electric Big Bend Power Station Modernization

On May 24, 2018, Tampa Electric announced its intention to invest approximately $850 million USD to modernize the Big Bend Power Station. This modernization project includes conversion of Unit 1 from coal-fired to natural gas combined-cycle technology and the early retirement of Unit 2. This project has been initiated and is expected to be complete in 2023.

Tampa Electric Tax Reform and Storm Settlement

On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric that authorizes the utility to net the estimated amount of storm cost recovery against the return of estimated 2018 tax reform benefits to customers. Refer to the "Business Overview and Outlook – Emera Florida and New Mexico", and "Financial Highlights – Emera Florida and New Mexico" sections for further details.

NSPML

The Maritime Link entered service on January 15, 2018, enabling the transmission of electricity between Newfoundland and Nova Scotia. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction. Refer to the "Business Overview and Outlook – Corporate and Other – ENL" section for further details.

APPOINTMENTS

Board of Directors

Effective July 10, 2018, James V. Bertram joined the Emera Board of Directors. Mr. Bertram is currently Chair of the Board, and former President and Chief Executive Officer, of Keyera Corporation, a publicly-traded, midstream oil and gas operator based in Calgary, Alberta.

Effective July 10, 2018, Jochen E. Tilk joined the Emera Board of Directors. Mr. Tilk is the former Executive Chair of Nutrien Inc., a Canadian global supplier of agricultural products and services based in Saskatoon, Saskatchewan. He is the former President and Chief Executive Officer of Potash Corporation of Saskatchewan.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
Balance, December 31, 2016	210.02	$ 4,738
Conversion of Convertible Debentures	0.15	6
Issuance of common stock	14.61	680
Issued under Purchase Plans at market rate	3.89	182
Discount on shares purchased under Dividend Reinvestment Plan	–	(9)
Options exercised under senior management stock option plan	0.10	3
Employee Share Purchase Plan	–	1
Balance, December 31, 2017	228.77	$ 5,601
Conversion of Convertible Debentures	0.01	–
Issuance of common stock (1)	0.45	22
Issued under Purchase Plans at market rate	4.87	200
Discount on shares purchased under Dividend Reinvestment Plan	–	(9)
Options exercised under senior management stock option plan	0.02	1
Employee Share Purchase Plan	–	1
Balance, December 31, 2018	**234.12**	**$ 5,816**

(1) In Q1 2018, Emera issued 0.45 million common shares to facilitate the creation and issuance of 1.8 million depository receipts in connection with the ICDU share acquisition. The depository receipts are listed on the Bahamas International Securities Exchange.

As at February 12, 2019, the amount of issued and outstanding common shares was 234.2 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, 2018 was 234.9 million (2017 – 215.3 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2018 was 233.0 million (2017 – 213.4 million).

FINANCIAL HIGHLIGHTS

EMERA FLORIDA AND NEW MEXICO

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 499**	$ 470	**$ 2,059**	$ 2,048
Operating revenues – regulated gas	**211**	206	**764**	732
Operating revenues – non-regulated	**3**	4	**13**	13
Total operating revenues	**713**	680	**2,836**	2,793
Regulated fuel for generation and purchased power	**145**	143	**610**	634
Regulated cost of natural gas	**91**	84	**300**	292
Adjusted contribution to consolidated net income – USD	**$ 77**	$ 63	**$ 331**	$ 295
Adjusted contribution to consolidated net income – CAD	**$ 101**	$ 80	**$ 428**	$ 382
Revaluation of US non-regulated deferred income taxes	**$ –**	$ (221)	**$ –**	$ (221)
Contribution to consolidated net income – USD	**$ 77**	$ (158)	**$ 331**	$ 74
Contribution to consolidated net income – CAD	**$ 101**	$ (203)	**$ 428**	$ 99
Adjusted contribution to consolidated earnings per common share – CAD	**$ 0.43**	$ 0.37	**$ 1.84**	$ 1.79
Contribution to consolidated earnings per common share – CAD	**$ 0.43**	$ (0.94)	**$ 1.84**	$ 0.46
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.31**	$ 1.28	**$ 1.29**	$ 1.34
EBITDA – USD	**$ 244**	$ 252	**$ 998**	$ 1,060
EBITDA – CAD	**$ 322**	$ 320	**$ 1,293**	$ 1,374

2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Emera Florida and New Mexico recorded a $221 million USD non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2017	**$ (158)**	**$ 74**
Increased electric operating revenues – see Operating Revenues – Regulated Electric below	29	11
Increased gas operating revenues – see Operating Revenues – Regulated Gas below	5	32
(Increased) decreased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	(2)	24
Increased cost of natural gas sold – see Regulated Cost of Natural Gas below	(7)	(8)
Increased OM&G expenses due to Tampa Electric's regulatory agreement to net storm costs and 2018 tax reform benefits resulting in storm costs recorded through OM&G, with the offsetting tax reform benefits recorded in income tax expense	(31)	(116)
Increased depreciation and amortization due to asset growth and PGS's regulatory agreement to net amortization of its MGP environmental regulatory asset and 2018 tax reform benefits. The offsetting tax reform benefits were recorded through income tax expense	(6)	(27)
Increased other income as the result of higher AFUDC earnings due to the construction of the first tranche of solar and the Big Bend modernization project	1	6
Decreased income tax expense due to the reduction of the US federal corporate income tax rate, the amortization of deferred income tax regulatory liabilities and decreased income before provision for income taxes. A portion of this benefit is offset by the additional OM&G and amortization costs discussed above	27	112
Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform	221	221
Other	(2)	2
Contribution to consolidated net income – 2018	**$ 77**	**$ 331**

Emera Florida and New Mexico's CAD adjusted contribution to consolidated net income increased by $21 million to $101 million in Q4 2018, from $80 million in Q4 2017. For the year ended December 31, 2018, Emera Florida and New Mexico's CAD adjusted contribution to consolidated net income increased $46 million to $428 million, from $382 million in 2017. These increases were primarily due to higher revenues as the result of customer growth, favourable weather in Florida and higher AFUDC earnings as a result of the completion of the first tranche of solar projects and the Big Bend modernization project at Tampa Electric.

The impact of the change in the foreign exchange rate increased CAD earnings for the quarter and year ended December 31, 2018, by $4 million and $1 million, respectively.

Emera Florida and New Mexico's adjusted contribution to consolidated net income by area is summarized in the following table:

For the millions of US dollars	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Tampa Electric	**$ 64**	$ 57	**$ 294**	$ 274
PGS	**11**	12	**47**	43
NMGC	**11**	10	**25**	22
Other (1)	**(9)**	(16)	**(35)**	(44)
Adjusted contribution to consolidated net income	**$ 77**	$ 63	**$ 331**	$ 295

(1) Other includes TECO Finance and administration costs.

Operating Revenues – Regulated Electric

Electric revenues increased $29 million to $499 million in Q4 2018, compared to $470 million in Q4 2017. For the year ended December 31, 2018, electric revenues increased $11 million to $2,059 million, from $2,048 million in 2017. Changes in both periods were primarily due to customer growth, favourable weather and higher rates related to the completion of the first tranche of solar projects. The year-over-year increase included an additional benefit to rates due to the completion of the Polk Power Station expansion.

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

Q4 Electric Revenues

millions of US dollars	2018	2017
Residential	$ 265	$ 237
Commercial	147	139
Industrial	40	39
Other (1)	47	55
Total	$ 499	$ 470

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

Annual Electric Revenues

millions of US dollars	2018	2017
Residential	$ 1,067	$ 1,006
Commercial	582	578
Industrial	161	158
Other (1)	249	306
Total	$ 2,059	$ 2,048

(1) Other includes sales to public authorities, off-system sales to other utilities and regulatory deferrals related to clauses.

Q4 Electric Sales Volumes

Gigawatt hours ("GWh")	2018	2017
Residential	2,320	2,113
Commercial	1,568	1,503
Industrial	490	495
Other	486	489
Total	4,864	4,600

Annual Electric Sales Volumes

GWh	2018	2017
Residential	9,418	9,029
Commercial	6,266	6,362
Industrial	2,014	2,024
Other	2,219	2,010
Total	19,917	19,425

Operating Revenues – Regulated Gas

Gas revenues increased $5 million to $211 million in Q4 2018, compared to $206 million in Q4 2017. For the year ended December 31, 2018, gas revenues increased $32 million to $764 million, from $732 million in 2017, due to higher clause recoveries, customer growth in Florida and favourable weather in Florida and New Mexico. This was partially offset by lower commodity costs in New Mexico.

Gas revenues and sales volumes are summarized in the following tables by customer class:

Q4 Gas Revenues

millions of US dollars	2018	2017
Residential	$ 116	$ 110
Commercial	61	60
Industrial (1)	9	9
Other (2)	25	27
Total	$ 211	$ 206

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

Annual Gas Revenues

millions of US dollars	2018	2017
Residential	$ 381	$ 367
Commercial	226	220
Industrial (1)	37	35
Other (2)	120	110
Total	$ 764	$ 732

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.

Q4 Gas Sales Volumes

Therms (millions)	2018	2017
Residential	141	113
Commercial	214	202
Industrial	339	292
Other	72	53
Total	766	660

Annual Gas Sales Volumes

Therms (millions)	2018	2017
Residential	389	344
Commercial	795	754
Industrial	1,338	1,216
Other	269	245
Total	2,791	2,559

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 5,238 MW. 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.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $2 million to $145 million in Q4 2018, compared to $143 million in Q4 2017. For the year ended December 31, 2018, regulated fuel for generation and purchased power decreased $24 million to $610 million, compared to $634 million in 2017 primarily due to a change in generation mix to lower-cost natural gas and solar, from coal, oil and petcoke.

Q4 Production Volumes

GWh	2018	2017
Natural gas	**4,160**	3,365
Coal	**430**	905
Oil and petcoke	**–**	228
Solar	**68**	9
Purchased power	**495**	171
Total production volumes	**5,153**	4,678

Annual Production

GWh	2018	2017
Natural gas	**16,097**	13,685
Coal	**3,088**	5,089
Oil and petcoke	**472**	924
Solar	**118**	45
Purchased power	**1,222**	559
Total production volumes	**20,997**	20,302

Q4 Average Fuel Costs

US dollars	2018	2017
Dollars per Megawatt hour ("MWh")	**$ 28**	$ 31

Annual Average Fuel Costs

US dollars	2018	2017
Dollars per MWh	**$ 29**	$ 31

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 (renewable energy from solar), 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.

Regulated Cost of Natural Gas

PGS and NMGC purchase gas from various suppliers depending on the needs of their customers. In Florida, 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 natural gas is transported on major interstate pipelines and NMGC's intrastate transmission system to customers.

In Florida, natural gas service is unbundled for non-residential customers and residential customers who use more than 1,999 therms annually and elect the option. In New Mexico, NMGC is required to provide transportation-only services for all customer classes if requested. 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.

Regulated cost of natural gas increased $7 million to $91 million in Q4 2018, compared to $84 million in Q4 2017. For the year ended December 31, 2018, regulated cost of natural gas increased $8 million to $300 million, compared to $292 million in 2017. The increases were primarily due to higher sales volumes in Florida and New Mexico and higher commodity costs in Florida partially offset by lower commodity costs in New Mexico.

Gas sales by type are summarized in the following tables:

Q4 Gas Sales Volumes by Type

Therms (millions)	**2018**	2017
System Supply	**242**	194
Transportation	**524**	466
Total	**766**	660

Annual Gas Sales Volumes by Type

Therms (millions)	**2018**	2017
System Supply	**745**	671
Transportation	**2,046**	1,888
Total	**2,791**	2,559

Gas sales volumes increased for the quarter and year ended December 31, 2018, primarily due to customer growth in Florida and favourable winter weather in Florida and New Mexico.

Regulatory Recovery Mechanisms

Tampa Electric

Fuel Recovery Clause

Tampa Electric has a fuel recovery clause approved by the FPSC, allowing it the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between prudently incurred 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.

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 the reserve.

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 actual 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. PGS has 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 a replacement program 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 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. 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.

NSPI

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 385**	$ 355	**$ 1,440**	$ 1,338
Regulated fuel for generation and purchased power [(1)]	**179**	141	**639**	477
Contribution to consolidated net income	**$ 28**	$ 23	**$ 131**	$ 129
Contribution to consolidated earnings per common share – basic	**$ 0.12**	$ 0.11	**$ 0.56**	$ 0.60
EBITDA	**$ 126**	$ 104	**$ 498**	$ 466

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Consolidated Income Statement, however it is excluded in the segment overview. The amounts excluded were $(19) million in Q4 2018 (2017 – $16 million) and $(46) million for the year ended December 31, 2018 (2017 – $59 million).

Net Income

Highlights of the net 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 – 2017	**$ 23**	**$ 129**
Increased operating revenues – see Operating Revenues – Regulated Electric below	30	102
Increased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	(38)	(162)
Decreased FAM and fixed cost deferrals due to a current year total under-recovery of fuel costs, compared to the prior year total over-recovery of fuel costs and the lower application of non-fuel revenues. Year-over-year was partially offset by the 2017 refund to customers of 2016 fuel costs	35	105
Increased OM&G expenses in 2018 primarily due to storm costs	(7)	(19)
Increased depreciation and amortization due to increased property, plant and equipment	(4)	(12)
Increased interest expense, net, year-over-year primarily due to higher average interest rate on the revolving credit facility and higher interest on the FAM regulatory deferral	(4)	(9)
Increased income tax expense primarily due to change in tax reserve	(8)	(8)
Other	1	5
Contribution to consolidated net income – 2018	**$ 28**	**$ 131**

NSPI's contribution to consolidated net income increased $5 million to $28 million in Q4 2018 from $23 million in Q4 2017. For the year ended December 31, 2018, NSPI's contribution to consolidated net income increased $2 million to $131 million from $129 million in 2017. These increases were the result of increased sales volume due to load growth and weather and decreased FAM and fixed cost deferral expense. This was partially offset by increased depreciation and amortization, OM&G and interest expenses.

Operating Revenues – Regulated Electric

Operating revenues increased $30 million to $385 million in Q4 2018, compared to $355 million in Q4 2017. Revenues increased as a result increased sales volumes due to load growth and weather.

For the year ended December 31, 2018, operating revenues increased $102 million to $1,440 million, compared to $1,338 million in 2017. Revenues increased due to increased sales volume due to load growth and weather, the refund to customers of prior year over-recovery of fuel costs in 2017, and increased fuel related electricity pricing in 2018. This was partially offset by the Maritime Link assessment.

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

Q4 Electric Revenues

millions of Canadian dollars	**2018**	2017
Residential	**$ 199**	$ 178
Commercial	**107**	101
Industrial	**62**	56
Other	**10**	13
Total	**$ 378**	$ 348

Annual Electric Revenues

millions of Canadian dollars	**2018**	2017
Residential	**$ 731**	$ 679
Commercial	**405**	387
Industrial	**233**	200
Other	**43**	43
Total	**$ 1,412**	$ 1,309

Q4 Electric Sales Volumes

GWh	**2018**	2017
Residential	**1,259**	1,120
Commercial	**799**	771
Industrial	**669**	637
Other	**76**	85
Total	**2,803**	2,613

Annual Electric Sales Volumes

GWh	**2018**	2017
Residential	**4,581**	4,374
Commercial	**3,102**	3,060
Industrial	**2,611**	2,466
Other	**323**	345
Total	**10,617**	10,245

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $38 million to $179 million in Q4 2018, compared to $141 million in Q4 2017. For the year ended December 31, 2018, regulated fuel for generation and purchased fuel power increased $162 million to $639 million, compared to $477 million in 2017. Changes in both periods were primarily due to the payment of the Maritime Link assessment, increased commodity prices, and increased sales volume.

NSPI's FAM regulatory liability balance decreased $16 million from $177 million at December 31, 2017 to $161 million at December 31, 2018 primarily due to the net under-recovery of current period fuel costs and the refund to customers of the 2017 Maritime Link assessment. This was partially offset by the recovery in 2018 of the Maritime Link assessment to be refunded to customers as part of the assessment decision.

Q4 Production Volumes

GWh	2018	2017
Coal	**1,466**	1,168
Natural gas	**275**	349
Oil and petcoke	**254**	352
Purchased power – other	**175**	220
Total non-renewables	**2,170**	2,089
Purchased power – IPP	**369**	374
Wind and hydro – renewables	**318**	190
Purchased power – Community Feed-in Tariff program ("COMFIT")	**153**	158
Biomass – renewables	**60**	53
Total renewables	**900**	775
Total production volumes	**3,070**	2,864

Annual Production Volumes

GWh	2018	2017
Coal	**4,930**	4,839
Natural gas	**1,427**	1,444
Oil and petcoke	**1,246**	1,169
Purchased power – other	**540**	481
Total non-renewables	**8,143**	7,933
Purchased power – IPP	**1,275**	1,246
Wind and hydro – renewables	**1,202**	1,121
Purchased power – COMFIT	**553**	525
Biomass – renewables	**189**	153
Total renewables	**3,219**	3,045
Total production volumes	**11,362**	10,978

Q4 Average Fuel Costs

	2018	2017
Dollars per MWh	**$ 58**	$ 49

Annual Average Fuel Costs

	2018	2017
Dollars per MWh	**$ 56**	$ 43

Average fuel cost per MWh increased in Q4 2018 and for the year ended December 31, 2018, compared to 2017, due to payment of the Maritime Link assessment and increased commodity pricing.

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has PPAs 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 hydro and wind have no fuel cost component. After hydro and wind, historically, petcoke and coal have the lowest per unit fuel cost, followed by natural gas. Oil, biomass and purchased power have the next lowest fuel cost, depending on the relative pricing of each.

The generation mix has transformed 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.

Regulatory Recovery Mechanisms

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* (the "Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are 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 has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel costs from customers through annual fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

EMERA MAINE

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 50**	$ 55	**$ 214**	$ 228
Regulated fuel for generation and purchased power (1)	**10**	17	**42**	64
Contribution to consolidated net income – USD	**$ 9**	$ 7	**$ 34**	$ 36
Contribution to consolidated net income – CAD	**$ 11**	$ 8	**$ 44**	$ 46
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.05**	$ 0.04	**$ 0.19**	$ 0.22
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.32**	$ 1.27	**$ 1.30**	$ 1.30
EBITDA – USD	**$ 25**	$ 23	**$ 107**	$ 107
EBITDA – CAD	**$ 33**	$ 29	**$ 139**	$ 139

(1) Regulated fuel for generation and purchased power includes transmission pool expenses.

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2017	**$ 7**	**$ 36**
Decreased operating revenues – see Operating Revenues – Regulated Electric section below	(5)	(14)
Decreased regulated fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power section below	7	22
Increased OM&G primarily due to increased storm restoration work, higher medical costs, and regulatory adjustments related to the distribution rate case, partially offset by higher capitalized construction overheads in 2018	–	(8)
Increased depreciation and amortization primarily due to increased regulatory amortization as a result of reduced purchase power contracts and higher plant in service	(2)	(14)
Decreased income tax expense primarily due to the reduction of the US federal corporate income tax rate and decreased income before provision for income taxes	2	13
Other	–	(1)
Contribution to consolidated net income – 2018	**$ 9**	**$ 34**

Emera Maine's CAD contribution to consolidated net income increased by $3 million to $11 million in Q4 2018, from $8 million in Q4 2017. For the year ended December 31, 2018, Emera Maine's CAD contribution to consolidated net income decreased $2 million to $44 million, from $46 million in 2017. The foreign exchange rate had minimal impact for the quarter and year ended December 31, 2018.

Operating Revenues – Regulated Electric

Operating revenues decreased $5 million to $50 million in Q4 2018, compared to $55 million in Q4 2017. For the year ended December 31, 2018, operating revenues decreased $14 million to $214 million in 2018, from $228 million in 2017. The year-over-year decrease was due to reduced transmission pool revenue primarily as a result of lower rates and lower stranded cost revenue primarily due to the expiration of a major purchased power contract. These decreases were partially offset by increased load due to favourable summer weather.

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		2018		2017
Electric revenues	**$**	**41**	$	41
Transmission pool revenues		**8**		10
Resale of purchased power		**1**		4
Operating revenues – regulated electric	**$**	**50**	$	55

Annual Operating Revenues – Regulated Electric

millions of US dollars		2018		2017
Electric revenues	**$**	**165**	$	169
Transmission pool revenues		**41**		48
Resale of purchased power		**8**		11
Operating revenues – regulated electric	**$**	**214**	$	228

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

Q4 Electric Revenues

millions of US dollars		2018		2017
Residential	**$**	**23**	$	21
Commercial		**16**		16
Industrial		**3**		2
Other (1)		**(1)**		2
Total	**$**	**41**	$	41

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

Annual Electric Revenues

millions of US dollars		2018		2017
Residential	**$**	**83**	$	81
Commercial		**62**		62
Industrial		**12**		12
Other (1)		**8**		14
Total	**$**	**165**	$	169

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

Q4 Electric Sales Volumes

GWh	2018	2017
Residential	**218**	207
Commercial	**192**	194
Industrial	**89**	87
Other	**3**	3
Total	**502**	491

Annual Electric Sales Volumes

GWh	2018	2017
Residential	**827**	802
Commercial	**769**	773
Industrial	**354**	349
Other	**12**	14
Total	**1,962**	1,938

Regulated Fuel for Generation and Purchased Power

Emera Maine's regulated fuel for generation and purchased power decreased $7 million to $10 million in Q4 2018, compared to $17 million in Q4 2017. For the year ended December 31, 2018 regulated fuel for generation and purchased power decreased $22 million to $42 million, from $64 million in 2017 due to the expiration of a major purchased power contract.

2017 Revaluation of US Regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017* Emera Maine recorded a $112 million USD non-cash provisional revaluation of existing US regulated net deferred income tax liabilities. Emera Maine recorded an equivalent increase of a regulatory liability as the impact of lower US taxes is expected to be returned to customers over time, as required by the Act or by order of the regulator. As a result, the deferred tax adjustment for Emera Maine had an impact on the 2017 balance sheet but no impact on 2017 earnings. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation.

Regulatory Recovery Mechanisms

Emera Maine's distribution operations and stranded cost recoveries are regulated by the MPUC. The transmission operations are regulated by the FERC. Rates for these three elements are established in distinct regulatory proceedings.

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. For stranded cost recoveries, Emera Maine is 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. Emera Maine's transmission businesses operate based on formulas utilizing prior year actual transmission investments and operating costs. Emera Maine collects revenue for its bulk transmission assets from ISO New England. Emera Maine is also required to contribute towards the total cost of the ISO New England pool transmission facilities on a ratable basis according to the proportion of the total New England load that their customers represent.

EMERA CARIBBEAN

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Operating revenues – regulated electric	**$ 90**	$ 84	**$ 360**	$ 334
Regulated fuel for generation and purchased power	**45**	41	**183**	152
Adjusted contribution to consolidated net income	**$ 11**	$ 1	**$ 35**	$ 24
Adjusted contribution to consolidated net income – CAD	**$ 14**	$ 1	**$ 45**	$ 31
After-tax equity securities mark-to-market gain (loss)	**(2)**	–	**(3)**	–
Contribution to consolidated net income	**$ 9**	$ 1	**$ 32**	$ 24
Contribution to consolidated net income – CAD	**$ 12**	$ 1	**$ 41**	$ 31
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$ 0.06**	$ –	**$ 0.19**	$ 0.15
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.05**	$ –	**$ 0.18**	$ 0.15
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.33**	$ 1.25	**$ 1.31**	$ 1.30
Adjusted EBITDA	**$ 22**	$ 11	**$ 93**	$ 87
Adjusted EBITDA – CAD	**$ 30**	$ 14	**$ 121**	$ 113

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2017	**$ 1**	**$ 24**
Increased operating revenues – see Operating Revenues – Regulated Electric below	6	26
Increased regulated fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	(4)	(31)
Increased other income due to the 2017 impairment charge as a result of damage to Domlec's assets from Hurricane Maria and the recognition of gains on the sale of investment securities in 2018 related to the BLPC self-insurance fund	6	6
Decreased OM&G costs due to operational cost savings at GBPC and BLPC quarter-over-quarter. Year-over-year, decreased OM&G due to operational cost savings at GBPC and lower maintenance at Domlec	3	5
Other	(3)	2
Contribution to consolidated net income – 2018	**$ 9**	**$ 32**

Emera Caribbean's CAD contribution to consolidated net income increased $11 million to $12 million in Q4 2018, compared to $1 million in Q4 2017. For the year ended December 31, 2018, Emera Caribbean's CAD contribution to consolidated net income increased $10 million to $41 million in 2018, compared to $31 million in 2017. These increases were primarily due to the impairment charge recognized in 2017, lower 2018 operating costs at GBPC and Domlec and gains on the sale of equity securities in 2018. The foreign exchange rate had minimal impact for the three months and year ended December 31, 2018.

Operating Revenues – Regulated Electric

Operating revenues increased $6 million to $90 million in Q4 2018, compared to $84 million in Q4 2017. This increase reflected higher sales volumes at Domlec due to the impact of Hurricane Maria in 2017, increased fuel charge as a result of higher fuel prices in 2018 at BLPC and higher sales volumes at GBPC due to continued recovery from Hurricane Matthew.

For the year ended December 31, 2018, operating revenues increased $26 million to $360 million, compared to $334 million in 2017 due to increased fuel charge as a result of higher fuel prices in 2018 at BLPC, partially offset by lower sales volumes at Domlec in 2018 due to the impact of Hurricane Maria.

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

Q4 Electric Revenues

millions of US dollars

		2018		2017
Residential	$	**30**	$	27
Commercial		**52**		49
Industrial		**6**		6
Other		**2**		2
Total	$	**90**	$	84

Annual Electric Revenues

millions of US dollars

		2018		2017
Residential	$	**119**	$	110
Commercial		**208**		191
Industrial		**23**		23
Other		**7**		7
Total	$	**357**	$	331

Q4 Electric Sales Volumes

GWh

	2018	2017
Residential	**113**	105
Commercial	**186**	182
Industrial	**21**	20
Other	**4**	4
Total	**324**	311

Annual Electric Sales Volumes

GWh

	2018	2017
Residential	**446**	462
Commercial	**748**	753
Industrial	**84**	85
Other	**15**	17
Total	**1,293**	1,317

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $4 million to $45 million in Q4 2018, compared to $41 million in Q4 2017 and for the year ended December 31, 2018, increased $31 million to $183 million compared to $152 million in 2017, primarily due to higher oil prices.

Q4 Production Volumes

GWh

	2018	2017
Oil	**335**	334
Hydro	**7**	2
Solar	**5**	5
Purchased Power	**7**	5
Total	**354**	346

Annual Production Volumes

GWh

	2018	2017
Oil	**1,330**	1,366
Hydro	**24**	27
Solar	**18**	18
Purchased Power	**26**	20
Total	**1,398**	1,431

Q4 Average Fuel Costs

		2018		2017
Dollars per MWh	$	**127**	$	119

Annual Average Fuel Costs

		2018		2017
Dollars per MWh	$	**131**	$	106

Average fuel cost per MWh increased for the quarter and year-to-date, compared to 2017, due to higher oil prices.

Regulatory Recovery Mechanisms

BLPC

BLPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The FTC approves 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 prudently incurred fuel costs from customers in a timely manner.

As a result of Hurricane Matthew in 2016, a regulatory asset was established to recover associated restoration costs. In addition, 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. 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 asset, until such time as the asset is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory asset, the excess will be placed in a new storm reserve. If the Hurricane Matthew deferral is not fully recovered at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

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 prudently incurred fuel costs from customers in a timely manner.

EMERA ENERGY

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Marketing and trading margin (1) (2)	**$ 42**	$ 24	**$ 115**	$ 44
Electricity and capacity sales (3)	**132**	115	**445**	345
Total operating revenues – non-regulated	**174**	139	**560**	389
Non-regulated fuel for generation and purchased power (4)	**68**	65	**238**	214
Adjusted contribution to consolidated net income	**$ 44**	$ 26	**$ 120**	$ 24
Revaluation of US non-regulated deferred income taxes	**$ –**	$ 12	**$ –**	$ 12
After-tax derivative mark-to-market gain (loss)	**67**	(48)	**45**	57
Contribution to consolidated net income (loss)	**$ 111**	$ (10)	**$ 165**	$ 93
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.19**	$ 0.12	**$ 0.52**	$ 0.11
Contribution to consolidated earnings per common share – basic	**$ 0.47**	$ (0.05)	**$ 0.71**	$ 0.44
Adjusted EBITDA				
Emera Energy Services	**$ 33**	$ 20	**$ 85**	$ 25
Emera Energy Generation	**34**	34	**125**	66
Equity Investment in Bear Swamp	**10**	7	**32**	16
Total	**$ 77**	$ 61	**$ 242**	$ 107

(1) Marketing and trading margin represents Emera Energy Service's purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market gain of $87 million in Q4 2018 (2017 – $37 million loss) and a gain of $16 million for the year ended December 31, 2018 (2017 – $119 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market gain of $10 million in Q4 2018 (2017 – $40 million loss) and a gain of $38 million for the year ended December 31, 2018 (2017 – $43 million loss).
(4) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market of nil in Q4 2018 (2017 – $3 million gain) and a gain of $5 million for the year ended December 31, 2018 (2017 – $1 million loss).

2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Emera Energy recorded a $12 million non-cash income tax recovery resulting from the provisional revaluation of existing US non-regulated net deferred income tax liabilities. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Mark-to-Market Adjustments

Emera Energy's "Marketing and trading margin", "Electricity and capacity sales", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by MTM adjustments. 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 changes for this quarter and for the year are explained in the chart below.

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities, and natural gas producers in northeastern North America. 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.

Net Income

Highlights of the net 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 – 2017	**$ (10)**	**$ 93**
Increased marketing and trading margin – see Emera Energy Services below	18	71
Increased electricity and capacity sales – see Emera Energy Generation below	17	100
Increased non-regulated fuel for generation and purchased power – see Emera Energy Generation below	(3)	(24)
Increased OM&G expenses due to increased performance-based compensation resulting from the increased marketing and trading margin; and the impact of an unplanned outage at Bridgeport Energy in 2017 that resulted in higher capitalization of maintenance spend compared to 2018	(11)	(20)
Increased income from equity investments mainly due to higher capacity prices at Bear Swamp in 2018	4	15
Increased income tax expense due to increased income before provision for income taxes, partially offset by the reduction of the US federal corporate income tax rate	(5)	(41)
Increased mark-to-market gain, net of tax quarter-over-quarter primarily due to changes in existing contract positions. Year-over-year decreased mark-to-market gain, net of tax due to a larger reversal of mark-to-market losses in 2017 compared to 2018 and change in existing contract positions, partially offset by lower amortization of gas transportation assets in 2018	115	(12)
Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform	(12)	(12)
Other	(2)	(5)
Contribution to consolidated net income – 2018	**$ 111**	**$ 165**

Excluding the change in mark-to-market and the deferred tax revaluation in 2017, Emera Energy's contribution to consolidated net income increased quarter-over-quarter due to the favourable impact of reduced maintenance on key pipelines in Q4 2018 on Emera Energy Services; and increased capacity prices for Emera Energy Generation. The year-over-year increase was also a result of the impact of favourable weather in 2018 on the business overall.

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 electricity, the related transportation and transmission 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. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the US Gulf Coast and Midwest/Central Canadian natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES 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.

Marketing and Trading Margin

Marketing and trading margin increased $18 million to $42 million in Q4 2018, compared to $24 million in Q4 2017, which saw significant pipeline maintenance that reduced margins on hedged capacity.

Marketing and trading margin increased $71 million to $115 million in 2018, compared to $44 million in 2017. In addition to the Q4 2018 explanation above, this increase was due to the favourable impact of cold weather in early 2018 in several key market areas, which resulted in higher market prices and volatility that led to higher margins; and also provided favourable hedging opportunities for the first quarter of 2018. The impact of warmer summer weather in 2018 compared to 2017, also contributed to the increase.

Emera Energy Generation

Emera Energy wholly owns and operates a portfolio of high efficiency, non-utility electricity generating facilities in northeast North America. On November 26, 2018, Emera announced an agreement to sell its three New England Gas Generating facilities. The transaction is expected to close in the first quarter of 2019. Refer to the "Developments" section for further details.

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	Connecticut	560	1999	Natural gas	Selling electricity and capacity to ISO-NE
Tiverton	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 PPA November – March; Selling electricity to Maritimes and ISO-NE for remainder of year; Selling capacity to ISO-NE
Brooklyn	Nova Scotia	30	1996	Biomass	Long-term PPA
Total Maritime Canada		**320**			
Total EEG		**1,435**			

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 due largely to power demand and fuel prices which impact margins. 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; and the impact on margins of generally higher natural gas pricing in the winter months when it is also required for heating load.

Q4 Electricity and Capacity Sales

For the millions of Canadian dollars						Three months ended December 31
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Electricity sales	**$ 81**	$ 78	**$ 11**	$ 9	**$ 92**	$ 87
Capacity sales	**40**	27	**–**	1	**40**	28
Electricity and capacity sales	**$ 121**	$ 105	**$ 11**	$ 10	**$ 132**	$ 115

Q4 Non-Regulated Fuel for Generation and Purchased Power

For the millions of Canadian dollars						Three months ended December 31
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Non-regulated fuel for generation and purchased power	**$ 66**	$ 63	**$ 2**	$ 1	**$ 68**	$ 64

Annual Electricity and Capacity Sales

For the millions of Canadian dollars						Year ended December 31
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Electricity sales	**$ 279**	$ 209	**$ 30**	$ 53	**$ 309**	$ 262
Capacity sales	**136**	80	**–**	3	**136**	83
Electricity and capacity sales	**$ 415**	$ 289	**$ 30**	$ 56	**$ 445**	$ 345

Annual Non-Regulated Fuel for Generation and Purchased Power

For the millions of Canadian dollars						Year ended December 31
	New England		Maritime Canada		Total	
	2018	2017	**2018**	2017	**2018**	2017
Non-regulated fuel for generation and purchased power	**$ 226**	$ 175	**$ 11**	$ 35	**$ 237**	$ 210

Emera Energy evaluates electricity sales and non-regulated fuel for generation and purchased power on a combined basis (excluding Capacity sales) for its NEGG facilities because the sales price of electricity and the cost of natural gas used to generate it are highly correlated in that market. NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $15 million in Q4 2018 and Q4 2017.

NEGG's electricity sales net of non-regulated fuel for generation and purchased power was $53 million in 2018, compared to $34 million in 2017. This increase of $19 million was due to the impact of an unplanned outage at Bridgeport Energy from mid-March 2017 to mid-June 2017 and higher realized electricity pricing in 2018 compared to 2017, reflecting more favourable market conditions, specifically the impact of weather.

Capacity sales increased $12 million to $40 million in Q4 2018, compared to $28 million in Q4 2017; and increased $53 million to $136 million in 2018, compared to $83 million in 2017. These increases reflected higher capacity prices that came into effect for NEGG in June 2017 and June 2018.

The year-over-year reduction in electricity sales and non-regulated fuel for generation and purchased power in Maritime Canada in 2018, compared to 2017, reflected renegotiation of the Bayside Power PPA, providing increased dispatch flexibility, while maintaining the net revenue stream for the facility.

Operating Statistics

For the						Three months ended December 31
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2018	2017	**2018**	2017	**2018**	2017
New England	**1,269**	1,413	**86.3%**	94.9%	**51.5%**	57.4%
Maritime Canada	**32**	40	**89.7%**	77.8%	**4.5%**	5.6%
Total	**1,301**	1,453	**87.0%**	91.0%	**41.0%**	45.8%

For the						Year ended December 31
	Sales Volumes (GWh) (1)		Plant Availability (%) (2)		Net Capacity Factor (%) (3)	
	2018	2017	**2018**	2017	**2018**	2017
New England	**5,386**	3,909	**91.5%**	81.8%	**55.1%**	40.0%
Maritime Canada	**373**	700	**93.8%**	73.0%	**13.3%**	25.0%
Total	**5,759**	4,609	**92.0%**	79.9%	**45.8%**	36.7%

(1) Sales volumes represent the actual electricity output of the plants.
(2) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running. Effectively, it represents 100 per cent 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.

NEGG sales volumes, plant availability and net capacity factor were lower quarter-over-quarter, reflecting more planned outage hours at the Bridgeport facility in Q4 2018. Year-over-year sales volumes, plant availability and net capacity factor were higher due to the impact of an unplanned outage at the Bridgeport facility from mid-March to mid-June 2017 and favourable market conditions in Q3 2018, compared to Q3 2017.

Maritime Canada plant availability was higher year-over-year due to a planned outage at the Bayside facility in Q2 2017. Sales volumes and capacity factor were lower due to negotiated changes to Bayside Power's PPA.

CORPORATE AND OTHER

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Operating revenues – regulated gas	**$ 16**	$ 13	**$ 57**	$ 52
Non-regulated operating revenue	**12**	19	**47**	75
Total operating revenue	**$ 28**	$ 32	**$ 104**	$ 127
Intercompany revenue (1)	**10**	10	**39**	39
Income from equity earnings	**21**	26	**109**	96
Interest expense, net (2)	**78**	76	**304**	293
Adjusted contribution to consolidated net income	**$ (31)**	$ (1)	**$ (97)**	$ (88)
After-tax mark-to-market gain (loss)	**(1)**	–	**(2)**	2
Revaluation of US non-regulated deferred income taxes	**–**	(46)	**–**	(46)
Contribution to consolidated net income (loss)	**$ (32)**	$ (47)	**$ (99)**	$ (132)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.13)**	$ –	**$ (0.42)**	$ (0.41)
Contribution to consolidated earnings per common share – basic	**$ (0.14)**	$ (0.22)	**$ (0.42)**	$ (0.62)
Adjusted EBITDA	**$ 13**	$ 45	**$ 131**	$ 136

(1) Intercompany revenue consists of interest from Brunswick Pipeline, M&NP and EEG.
(2) Interest expense, net excludes a pre-tax mark-to-market loss of $1 million in Q4 2018 (2017 – nil) and a loss of $2 million for the year-end December 31, 2018 (2017 – $3 million gain).

2017 Revaluation of US Non-regulated Deferred Income Taxes

In Q4 2017, due to enactment of the *US Tax Cuts and Jobs Act of 2017*, Corporate recorded a $46 million non-cash income tax expense resulting from the provisional revaluation of existing US non-regulated net deferred income tax assets. No further adjustments were recognized in 2018 and the Company has completed its accounting for this revaluation. Management believes excluding this revaluation from adjusted net income better distinguishes the ongoing operations of the business, and allows investors to better understand and evaluate the Company.

Net Income

Highlights of the net 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 (loss) – 2017	**$ (47)**	**$ (132)**
Decreased non-regulated operating revenue due to less project activity at EUS	(7)	(28)
Increased non-regulated direct costs quarter-over-quarter due to higher project costs in Q4 2018. Decreased non-regulated direct costs year-over-year due to lower project activity at EUS	(6)	16
Increased OM&G quarter-over-quarter due to timing of performance-based compensation	(12)	(1)
Income from equity investments – see income from Equity Investments below	(5)	13
Increased interest expense	(2)	(11)
Increased income tax recovery year-over-year due to remeasurement of certain deferred tax balances as a result of a change in Florida state tax apportionment factors and increased losses before provision for income taxes, partially offset by the reduction of the US federal corporate income tax rate	3	13
Revaluation of US non-regulated deferred income taxes in 2017 due to tax reform	46	46
Increased preferred stock dividends due to the issuance of preferred shares in Q2 2018	–	(7)
Other	(2)	(8)
Contribution to consolidated net income (loss) – 2018	**$ (32)**	**$ (99)**

Excluding the change in mark-to-market and the deferred tax revaluation in 2017, Corporate and Other's costs increased for the quarter and year-over-year. The increase in Q4 2018 was due to timing of performance-based compensation and changes in project costs. The year-over-year increase was due to lower project activity at EUS, increased interest expense and increased preferred dividends, partially offset by increased income tax recovery and increased equity earnings from NSPML and LIL.

Income from Equity Investments

Income from equity investments are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
M&NP	**$ 5**	$ 6	**$ 22**	$ 23
NSPML	**5**	10	**45**	36
LIL	**11**	10	**42**	37
Income from equity investments	**$ 21**	$ 26	**$ 109**	$ 96

In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI. Prior to Q1 2018, NSPML recorded non-cash AFUDC earnings as it was under construction.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments and select asset sales. Utility customer bases are diversified by both sales volumes and rates 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. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. Emera's subsidiaries 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 and maintain their credit metrics.

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera expects to invest approximately $6.5 billion over the three-year period from 2019 to 2021 on rate base growth in the Company's regulated utilities. Over 85 per cent of the investment is expected to be in Florida and Nova Scotia. Capital expenditures at the regulated utilities are subject to regulatory approval. Emera plans to use cash from operations, debt raised at the utilities and proceeds from the NEGG and other select asset sales to support normal operations, repayment of existing debt and capital requirements. Emera has credit facilities with varying maturities that cumulatively provide $3.1 billion of credit (refer to notes 22 and 24 in the consolidated financial statements for additional information regarding the credit facilities).

As a result of US tax reform, 2019 base rates have been adjusted in the majority of Emera's US regulated utilities to reflect lower income tax expense and amortization of the deferred income tax regulatory liability recorded at the date of enactment. The resulting decrease in cash from operations will be partially offset by cash refunds associated with Alternative Minimum Tax ("AMT") credits beginning in 2019.

Emera believes its liquidity is adequate given the Company's expected operating cash flows, capital expenditures, and related financing plans.

CONSOLIDATED CASH FLOW HIGHLIGHTS

Significant changes in the statements of cash flows between the years ended December 31, 2018 and 2017 include:

millions of Canadian dollars		2018		2017		$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$**	**503**	$	491	$	12
Provided by (used in):						
Operating cash flow before changes in working capital		**1,806**		1,297		509
Change in working capital		**(116)**		(104)		(12)
Operating activities		**1,690**		1,193		497
Investing activities		**(2,190)**		(1,761)		(429)
Financing activities		**344**		593		(249)
Effect of exchange rate changes on cash and cash equivalents		**25**		(13)		38
Cash, cash equivalents and restricted cash, end of period	**$**	**372**	$	503	$	(131)

Cash Flow from Operating Activities

Net cash provided by operating activities for the year ended December 31, 2018 increased $497 million to $1,690 million, compared to $1,193 million in 2017.

Cash from operations before changes in working capital increased $509 million. This was due to lower under-recovery from customers on clause related costs in 2018 than 2017, and lower pension contributions in 2018 at Emera Florida and New Mexico, increased capacity payments at NEGG, and increased marketing and trading margin at EES. These were partially offset by increased fuel for generation and purchased power at NSPI.

Changes in working capital decreased operating cash flows by $12 million. This decrease was due to unfavourable changes in cash collateral at NSPI and unfavourable changes in inventory at NSPI reflecting increased fuel purchases. These were partially offset by favourable changes in accounts receivable and accounts payable at Emera Florida and New Mexico, and NSPI and favourable changes in cash collateral at Emera Energy.

Cash Flow Used in Investing Activities

Net cash used in investing activities increased $429 million to $2,190 million for the year ended December 31, 2018, compared to $1,761 million in 2017 due to an increase in capital expenditures, partially offset by reduced equity contributions in NSPML and LIL in 2018, compared to 2017.

Capital expenditures, including AFUDC and net of proceeds from disposal of assets, for the year ended December 31, 2018 were $2,178 million, compared to $1,537 million in 2017. Details of capital expenditures are shown below:

- $1,567 million at Emera Florida and New Mexico (2017 – $914 million)
- $350 million at NSPI (2017 – $393 million)
- $103 million at Emera Maine (2017 – $85 million)
- $87 million at Emera Caribbean (2017 – $72 million)
- $33 million at Emera Energy (2017 – $47 million)
- $38 million at Corporate and Other (2017 – $26 million)

Cash Flow from Financing Activities

Net cash provided by financing activities decreased $249 million to $344 million for the year ended December 31, 2018, compared to $593 million in 2017. The decrease was due to the issuance of common stock in 2017 and increased 2018 dividends on common stock. These were partially offset by the issuance of preferred stock in 2018, increased borrowings under Emera's committed credit facilities in 2018, and a net increase of debt at Emera Florida and New Mexico.

WORKING CAPITAL

As at December 31, 2018, Emera's cash and cash equivalents were $316 million (2017 – $438 million) and Emera's investment in non-cash working capital was $449 million (2017 – $322 million). Of the cash and cash equivalents held at December 31, 2018, $280 million was held by Emera's foreign subsidiaries (2017 – $174 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.

CONTRACTUAL OBLIGATIONS

As at December 31, 2018, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt principal	$ 1,119	$ 898	$ 1,742	$ 758	$ 1,138	$ 9,847	$ 15,502
Interest payment obligations (1)	708	660	603	554	529	6,885	9,939
Purchased power (2)	204	203	209	208	209	2,194	3,227
Transportation (3) (4)	569	347	255	215	170	1,492	3,048
Pension and post-retirement obligations (5)	38	34	35	36	36	1,040	1,219
Fuel and gas supply	642	237	49	7	3	–	938
Capital projects (6)	524	147	45	11	3	8	738
Long-term service agreements (7) (8)	110	67	42	30	33	246	528
Asset retirement obligations	3	27	45	1	1	365	442
Equity investment commitments (9)	–	190	–	–	–	–	190
Leases and other (10)	18	15	10	9	7	75	134
Demand side management	44	1	–	–	–	–	45
Long-term payable	4	5	5	5	5	–	24
Convertible debentures	–	–	–	–	–	3	3
	$ 3,983	$ 2,831	$ 3,040	$ 1,834	$ 2,134	$ 22,155	$ 35,977

(1) 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, 2018, including any expected required payment under associated swap agreements.
(2) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(4) Includes $82 million related to NEGG transportation capacity ($5 million in 2019; $5 million in 2020; $5 million in 2021; $4 million in 2022; $4 million in 2023 and $59 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to "Developments" for additional information.
(5) Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2018. Credited service and earnings are assumed to be crystallized as at December 31, 2018. The Company's contractual obligations for post-retirement (non-pension) benefits assume members must be age 55 or over (50 for TECO Energy) as at December 31, 2018 to be eligible. As the defined benefit pension plans currently undergo 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.
(6) Includes $439 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.
(7) 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.
(8) Includes $248 million related to various long-term service agreements NEGG has entered into for maintenance of certain generating equipment ($46 million in 2019; $9 million in 2020; $24 million in 2021; $16 million in 2022; $16 million in 2023 and $137 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to "Developments" for additional information.
(9) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(10) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. In January 2018, NSPI started paying the UARB approved interim assessment payments and, as of December 31, 2018, $96 million had been paid to NSPML. The UARB approved payment for 2019 is $111 million and is subject to a $10 million holdback. Refer to note 14 to the consolidated financial statements for the year ended December 31, 2018 for additional information. After 2019, the timing of and amounts payable to NSPML will be subject to regulatory filings with the UARB, with expected filings in 2019 and 2020.

FORECASTED GROSS CONSOLIDATED CAPITAL EXPENDITURES

2019 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	$ 509	$ 105	$ –	$ 96	$ 8	$ –	$ 718
New renewable generation	282	–	–	16	–	–	298
Transmission	68	60	33	2	–	–	163
Distribution	323	125	32	33	–	–	513
Gas transmission and distribution	479	–	–	–	–	–	479
Facilities, equipment, vehicles, and other	161	50	31	12	–	6	260
	$ 1,822	$ 340	$ 96	$ 159	$ 8	$ 6	$ 2,431

DEBT MANAGEMENT

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate; access to approximately $3.1 billion committed syndicated revolving bank lines of credit in either CAD or USD per the table below.

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera – Operating and acquisition credit facility	June 2020 – Revolver	$ 900	$ 411	$ 489
Emera Florida and New Mexico – in USD – credit facilities	March 2019 – March 2022	1,500	871	629
NSPI – Operating credit facility	October 2023 – Revolver	600	518	82
Emera Maine – in USD – Operating credit facility	February 2023 – Revolver	80	24	56
Other – in USD – Operating credit facilities	Various	32	11	21

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 as at December 31, 2018. Emera's significant covenant is listed below:

	Financial Covenant	Requirement	As at December 31, 2018
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.60 : 1

Recent financing activities for Emera and its subsidiaries are discussed below:

Emera

On May 31, 2018, Emera issued 12 million 4.90 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series H at $25.00 per share for gross proceeds of $300 million and net proceeds of $295 million. The net proceeds of the preferred share offering were used for general corporate purposes. For further details, refer to note 27 to the 2018 annual consolidated financial statements. The offering was made under Emera's $750 million short form base shelf prospectus dated May 16, 2018. As at December 31, 2018, the Company has $450 million available for issuance under this prospectus, which expires on June 16, 2020.

Emera Florida and New Mexico

On October 4, 2018, TEC completed a $375 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.45 per cent and have a maturity date of June 15, 2049. On October 11, 2018 proceeds from this issuance were used to repay a $300 million USD 1-year term credit facility.

On June 7, 2018, TEC completed a $350 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.30 per cent and have a maturity date of June 15, 2048.

On April 10, 2018, TECO Energy/Finance repaid a $250 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

On March 23, 2018, TEC extended the maturity date of its $150 million USD accounts receivable collateralized borrowing facility from March 23, 2018 to March 22, 2021. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $300 million USD revolving credit facility by $100 million USD to $400 million USD. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $400 million USD term bank credit facility by $100 million USD to $500 million USD, and extended the maturity date from March 8, 2018 to March 8, 2019. There were no other changes in commercial terms.

NSPI

On October 31, 2018, NSPI amended its operating credit facility to extend the maturity from October 2021 to October 2023. There were no other changes in commercial terms.

Emera Maine

On November 15, 2018, Emera Maine completed a $50 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.71 per cent and will mature on November 15, 2048. Proceeds from this issuance were used for general corporate purposes.

On February 28, 2018, Emera Maine extended the maturity date of its $80 million USD operating credit facility from September 25, 2019 to February 28, 2023. There were no other changes in commercial terms.

ECI

On January 12, 2018, a wholly owned indirect subsidiary of ECI entered into a five year $18 million Bahamian dollar loan agreement with an interest rate of 4.00 per cent and maturity date of January 12, 2023.

EBP

On October 31, 2018, Emera Brunswick Pipeline amended its Credit Agreement to extend the maturity from February 2021 to February 2022. There were no other changes in commercial terms.

CREDIT RATINGS

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

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

On December 21, 2018, DBRS Limited affirmed NSPI's A (low) issuer and issue rating with a stable trend.

On December 19, 2018, Moody's Investor Services affirmed Emera's Baa3 (Negative) issuer rating and Emera US Finance LP's Baa3 guaranteed senior unsecured rating. At the same time, Moody's affirmed the Baa2 senior unsecured ratings of TECO Energy/TECO Finance and the A3 issuer and senior unsecured ratings of Tampa Electric Company, with a stable outlook.

On December 5, 2018, S&P Global Ratings affirmed its BBB+ long term corporate credit rating on Emera, NSPI, TECO Energy/Finance, TEC and NMGC and changed its ratings outlook to negative from stable.

SHARE CAPITAL

As at December 31, 2018, Emera had 234.12 million (2017 – 228.77 million) common shares issued and outstanding. For the year ended December 31, 2018, 5.34 million common shares were issued (2017 – 18.6 million) for net proceeds of $215 million (2017 – $857 million).

As at December 31, 2018, Emera had 41 million preferred shares issued and outstanding (2017 – 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 five-year period for the plans. The cash required in 2019 for defined benefit pension plans is expected to be $53 million (2018 – $51 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 $33 million for 2019 (2018 – $31 million actual).

DEFINED BENEFIT PENSION PLAN SUMMARY

millions of Canadian dollars — As at December 31, 2018

Plans by region	TECO Energy Pension Plans	NSPI Pension Plans	Emera Maine Pension Plans	Caribbean Plans	Total
Assets as at December 31, 2018	$ 899	$ 1,220	$ 170	$ 11	$ 2,300
Accounting obligation at December 31, 2018	1,023	1,406	206	15	2,650
Accounting expense during fiscal 2018	$ 25	$ 40	$ 4	$ 1	$ 70

OFF-BALANCE SHEET ARRANGEMENTS

DEFEASANCE

Upon privatization 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, 2018 totalled $759 million (2017 – $726 million). The securities are held in trust for 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.

GUARANTEES AND LETTERS OF CREDIT

Emera has the following significant guarantees and letters of credit on behalf of third parties outstanding that are not included within the Consolidated Balance Sheets as at December 31, 2018:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which is expected to terminate on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

The Company has standby letters of credit and surety bonds in the amount of $67 million USD to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in February 2019 and is renewed annually. The amount committed as of December 31, 2018 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The letter of credit expires in June 2019 and is renewed annually. The amount committed as at December 31, 2018 was $49 million.

DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 2021. The Company targets a long-term dividend payout ratio of 70 to 75 per cent, and while the payout ratio is likely to exceed that target in the forecast period, it is expected to return to that range over time. Emera Incorporated's common share dividends paid in 2018 were $2.2825 ($0.5650 in Q1, Q2, and Q3 and $0.5875 in Q4) per common share and $2.1325 ($0.5225 in Q1, Q2, and Q3 and $0.5650 in Q4) per common share for 2017, representing a payout ratio of 79 per cent of adjusted net income in 2018 and 86 per cent for 2017.

On August 9, 2018, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.26 to $2.35. The first quarterly dividend payment at the increased rate was paid on November 15, 2018.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Intercompany balances and intercompany 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. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are as follows:

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $21 million (2017 – nil) for the three months ended December 31, 2018 and $97 million for the year ended December 31, 2018 (2017 – nil). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments. Refer to the "Business Overview and Outlook – Corporate and Other – ENL" and "Contractual Obligations" sections for further details.
- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $7 million (2017 – $8 million) for the three months ended December 31, 2018 and $29 million for the year ended December 31, 2018 (2017 – $28 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2018 and at December 31, 2017.

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 and consistency 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, 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 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 changes in government and significant shifts in government policy including initiatives regarding deregulation or restructuring of the energy industry and shifts in policy which could occur as a result of climate change concerns. 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.

Deregulation or restructuring of the electric industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. Florida electric utilities, including Tampa Electric, have limited competition in their market for retail customers; however, there is currently a proposed constitutional initiative in Florida which, if passed, would grant customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity, and would limit the business of investor-owned utilities to construction, operation and repair of electrical transmission and distribution systems. This initiative is going through the process for potential inclusion as an amendment to the Florida Constitution, to be voted on in November 2020. Such a vote would be subject to Florida Supreme Court approving the placing of the amendment on the ballot and conditional on the initiative attracting a sufficient number of petition signatures. In the event the amendment achieves the 60 per cent required votes, the implementing legislation would be required to be passed by no later than June 1, 2023 and with effect by no later than 2025.

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. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

WEATHER AND CLIMATE CHANGE RISK

The Company is subject to a number of risks that arise or may arise from weather and climate change, including seasonal variations, the risk of changes in regulations (refer to "Changes in Environmental Legislation" risk), more frequent and intense weather events, and warming air temperatures.

Fluctuations in the amount of electricity or natural gas used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the Company's utilities. For example, electrical utilities operating in the US Northeast or Atlantic Canada could see lower demand in winter months if temperatures are warmer than expected. In the absence of a regulatory recovery mechanism for unanticipated resulting revenue losses, such events could have an effect on the results of operations, financial conditions or cash flows of the Company or its utilities.

Climate change is predicted to lead to increased frequency and intensity of weather events and related impacts such as storms, wildfires, flooding and storm surge. Extreme weather events create a risk of physical damage to the Company's assets. High winds can damage structures, and cause widespread damage to transmission and distribution infrastructure. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased intensity of flooding could adversely affect the operations of the Company's hydro-electric facilities.

The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce greater damage to coastal located generation and other facilities. Each of Emera's regulated electric utilities have programs for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is generally not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves or designated self-insurance funds, or after the fact through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review. The risk to generation assets is, in part, mitigated through the design, siting, construction and maintenance of such facilities, regular risk assessments, engineered mitigation, emergency storm response plans and insurance risk transfer.

Climate change is also characterized by increases in global air temperatures. Increased air temperatures may bring increased frequency and severity of wildfires, including within the Company's service territories in the southern United States. Increased air temperatures could also result in decreased efficiencies over time of both generation and transmission facilities.

The increased risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and vegetation management programs for electric transmission and distribution facilities. If it is found to be responsible for such a fire, the Company could suffer costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially affect Emera's business and financial results including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

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 waste management, wastewater discharges and aquatic and terrestrial habitats.

Beginning January 1, 2019, each province and territory in Canada is required to have a carbon pricing system which meets a benchmark set by the Government of Canada, failing which the Government of Canada would impose a carbon pricing system on each non-compliant province or territory equivalent to the federal benchmark. On October 23, 2018, the Government of Canada confirmed that the cap and trade carbon pricing system proposed by the Government of Nova Scotia met the federal benchmark. In the United States, the Environmental Protection Agency released a proposed rule to replace the Clean Power Plan, named the Affordable Clean Energy ("ACE") rule. The ACE rule proposes to establish GHG emission guidelines for states to address GHG emissions from existing fossil fuel-fired electricity generating units. Individual states continue to develop or administer GHG reduction initiatives. 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.

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.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of complying with applicable legal requirements and Company policy. 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.

CYBERSECURITY RISK

Emera is exposed to potential risks related to cyberattacks and unauthorized access. The Company increasingly relies on information technology systems and network infrastructure to manage its business and safely operate its assets; including controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other business systems. Emera also relies on third party service providers in order to conduct business. As the Company operates critical infrastructure, it may be at greater risk of cyberattacks by third parties, which could include nation-state controlled parties.

Cyberattacks can reach the Company's networks with access to critical assets and information via their interfaces with less critical internal networks or via the public internet. Cyberattacks can also occur via personnel with direct access to critical assets or trusted networks. Methods used to attack critical assets could include general purpose or energy-sector-specific malware delivered via network transfer, removable media, viruses, attachments or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

Despite security measures in place, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt operations or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers or the unavailability, release, destruction or misuse of critical, sensitive or confidential information. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Should such cyberattacks or unauthorized accesses materialize, the Company could suffer costs, losses and damages all, or some of which, may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially adversely affect Emera's business and financial results including its reputation and standing with customers, regulators, governments and financial markets. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. If any such security breaches occur, there is no assurance that they can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards, program maturity objectives and strategy derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and information technology including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation and Northeast Power Coordinating Council. The status of key elements of the Company's cybersecurity program is reported to the Audit Committee on a quarterly basis.

ENERGY CONSUMPTION RISK

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, customers' focus on energy efficiency and advancements in new technologies, such as rooftop solar, electric vehicles and battery storage. Government policies promoting distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings and cash flows. The Company's rate-regulated utilities are focused on understanding customer demand, energy efficiency and government policy to ensure that the impact of these activities benefit customers, that they do not negatively impact the reliability of the energy service the utilities provide and that they are addressed through regulations.

FOREIGN EXCHANGE RISK

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, 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 foreign currency derivative instruments to hedge specific transactions. The Company may enter into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams and capital expenditures. 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 do not impact net income as they are reported in AOCI.

LIQUIDITY AND CAPITAL MARKET RISK

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, select asset sales, short-term credit facilities, and ongoing access to capital markets. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to a number of risk factors, including financial market conditions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment. Emera is subject to risk with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access to cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

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 decrease in a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations. Emera manages this risk by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation, preferred share units and deferred share units.

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. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's 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.

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 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.

On November 26, 2018, Emera announced an agreement to sell its three NEGG facilities. The transaction is expected to close in the first quarter of 2019. Refer to the "Developments" section for further details.

COUNTERPARTY 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 specific accounts.

COUNTRY RISK

Earnings outside of Canada constituted 69 per cent (65 per cent from the US and 4 per cent from the Caribbean) of Emera's earnings in 2018 (2017 – 42 per cent, with 35 per cent from the US and 7 per cent from the Caribbean). Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. Emera's operations in some countries may be subject to changes in 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 commercial relationship risk by monitoring credit risk, as discussed above in Counterparty 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

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 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

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could adversely affect the Company's operations and financial results. Emera seeks to manage this risk through maintaining competitive compensation programs, a dedicated talent acquisition team, human resources programs and practices including ethics and diversity training, employee engagement surveys, succession planning for key positions and apprenticeship programs.

Approximately 40 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships 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.

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 assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. 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.

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.

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, interest rates and share prices 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, equity derivatives, 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 any gains or losses resulting from settlement of these derivatives 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 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 millions of Canadian dollars	**December 31 2018**	December 31 2017
Derivative instrument assets (current and other assets)	**$ –**	$ 7
Derivative instrument liabilities (current and long-term liabilities)	**(5)**	(7)
Net derivative instrument assets (liabilities)	**$ (5)**	$ –

HEDGING IMPACT RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2018	2017
Operating revenues – regulated	**$ 5**	$ (10)
Non-regulated fuel for generation and purchased power	**1**	3
Effective net gains (losses)	**$ 6**	$ (7)

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 millions of Canadian dollars	**December 31 2018**	December 31 2017
Derivative instrument assets (current and other assets)	**$ 104**	$ 181
Regulatory assets (current and other assets)	**6**	13
Derivative instrument liabilities (current and long-term liabilities)	**(6)**	(13)
Regulatory liabilities (current and long-term liabilities)	**(115)**	(183)
Net asset (liability)	**$ (11)**	$ (2)

REGULATORY IMPACT RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2018	2017
Regulated fuel for generation and purchased power (1)	**$ 11**	$ 17
Net gains (losses)	**$ 11**	$ 17

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

HFT 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 2018	December 31 2017
Derivative instruments assets (current and other assets)	**$ 62**	$ 63
Derivative instruments liabilities (current and long-term liabilities)	**(354)**	(290)
Net derivative instrument assets (liabilities)	**$ (292)**	$ (227)

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
	2018	2017
Non-regulated operating revenues	**$ 193**	$ 408
Non-regulated fuel for generation and purchased power	**2**	12
Net gains (losses)	**$ 195**	$ 420

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 2018	December 31 2017
Derivative instrument assets (current and other assets)	**$ 1**	$ 2
Net derivative instrument assets (liabilities)	**$ 1**	$ 2

OTHER DERIVATIVES RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2018	2017
Interest expense, net	**$ (1)**	$ 2
Total gains (losses)	**$ (1)**	$ 2

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). The Company's internal control framework is based on the criteria published in the Internal Control – Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company's DC&P and ICFR as at December 31, 2018 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

There were no changes in the Company's ICFR during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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, capitalized overhead and valuation of financial instruments. Actual results may differ significantly from these estimates.

RATE REGULATION

The rate-regulated accounting policies of Emera's rate regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from accounting policies for non-rate-regulated companies. 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 expectations 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. The application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

The Company has recorded $1,569 million (2017 – $1,411 million) of regulatory assets and $2,610 million (2017 – $2,468 million) of regulatory liabilities as at December 31, 2018.

ACCUMULATED RESERVE – COST OF REMOVAL

Tampa Electric, PGS, NMGC and NSPI recognize non-asset retirement obligation costs of removal as regulatory liabilities. These costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required costs of removal of property, plant and equipment upon retirement. The companies accrue for costs of removal 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 balance of the Accumulated reserve – cost of removal within regulatory liabilities was $955 million at December 31, 2018 (2017 – $894 million).

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 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 changes to pension costs in future periods.

The Company's accounting policy is to amortize the net actuarial gain or loss, that 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 (for the largest plans this is currently 7.5 years for the Canadian plans and a weighted average of 12.4 years for the US plans). The Company's use of smoothed asset values 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:

		2018		2017
	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	**3.63%**	**6.85%**	4.16%	7.00%
TECO Energy Group Supplemental Executive Retirement Plan (1)	**3.11% / 3.84%**	**N/A**	3.37% / 3.25%	N/A
TECO Energy Group Benefit Restoration Plan (1)	**3.26% / 3.76% / 4.01%**	**N/A**	3.64%	N/A
TECO Energy Post-retirement Health and Welfare Plan	**3.70%**	**N/A**	4.28%	N/A
New Mexico Gas Company Retiree Medical Plan	**3.71%**	**4.00%**	4.29%	7.00%
NSPI	**3.50%**	**6.00%**	3.84%	6.00%
Bangor Hydro (2)	**3.53%**	**6.55%**	4.04%	6.55%
Maine Public Service (2)	**3.45%**	**6.55%**	3.91%	6.55%
GBPC Salaried	**4.25%**	**6.00%**	4.25%	6.00%
GBPC Union	**5.00%**	**5.00%**	5.00%	5.00%

(1) The discount rate for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.
(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 was $115 million in 2018 (2017 – $105 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2018 benefit cost of $9 million and $6 respectively (2017 – $9 million and $6 million).

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 determine 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, inter-period changes to customer classes and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2018, unbilled revenues totalled $296 million (2017 – $278 million) on total annual operating revenues of $6,524 million (2017 – $6,226 million).

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 58 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 and accumulated depreciation.

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 $881 million for the year ended December 31, 2018 (2017 – $833 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. Application of the goodwill impairment test requires management judgment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. Significant assumptions used in the qualitative assessment include macroeconomic conditions, industry and market considerations and overall financial performance, among other factors.

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 chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test 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, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Significant assumptions used in estimating the fair value of a reporting unit 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.

At December 31, 2018, the Company had goodwill with a total carrying amount of $6,313 million (December 31, 2017 – $5,805 million). The change in the carrying value from 2017 to 2018 was a result of the strengthening US dollar on the goodwill balances. This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGI reporting units), Emera Maine and GBPC over the fair values assigned to individual assets acquired and liabilities assumed.

The fair market value of goodwill is subject to change 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 other fair value significant assumptions described above could also negatively impact goodwill in the future.

No impairment provisions with respect to goodwill were required for either 2018 or 2017.

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 intangibles 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. 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 outside of this annual analysis. The review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value.

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 material impairment provisions with respect to long-lived assets were required for 2018 or 2017.

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 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 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.

In response to the US enactment of the *Tax Cuts and Jobs Act* on December 22, 2017, Emera recorded an $813 million net revaluation of the Company's US deferred tax assets and liabilities at December 31, 2017. Management estimated the implications of the Act based on the best information available. No further adjustments were recorded in 2018 and the Company has completed its accounting for the revaluation of its US deferred income tax assets and liabilities resulting from the effects of the Act. The Company believes that its US based financing interest will be deductible under the Act. Any change in assumptions could have a material impact on the results of the Company. Refer to "Significant Items Affecting Earnings – US Tax Reform" for further details.

ASSET RETIREMENT OBLIGATIONS ("ARO")

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 uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations and advances in remediation technologies. Emera has AROs associated with the remediation of generation, transmission and distribution and pipeline assets.

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 recorded 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 generation, 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.

As at December 31, 2018, the AROs recorded on the balance sheet were $205 million (2017 – $172 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $451 million (2017 – $438 million), which will be incurred between 2019 and 2061. The majority of these costs will be incurred between 2028 and 2050.

CAPITALIZED OVERHEAD

As required by their respective regulators, Emera's rate regulated subsidiaries and regulated equity investments capitalize overhead costs that are attributable to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by the respective regulators. For the year ended December 31, 2018, $187 million of overhead costs (2017 – $156 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

The Company is required to determine the fair value of all derivatives except those which qualify for the normal purchase, normal sale exception. Fair value is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

LEVEL DETERMINATIONS AND CLASSIFICATIONS

The Company uses the Level 1, 2, and 3 classifications in the fair value hierarchy. The fair value measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the fair value. Fair values are determined, directly or indirectly, using inputs that are unobservable for the asset or liability. Only in limited circumstances does the Company enter into commodity transactions involving non-standard features where market observable data is not available, or contracts in which the terms extend beyond five years.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2018, are described as follows:

RECLASSIFICATION OF CERTAIN TAX EFFECTS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

In February 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Updates ("ASU") No. 2018-02, *Income Statement – Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The standard allows reclassification from accumulated other comprehensive income to retained earnings for certain tax effects resulting from the *US Tax Cuts and Jobs Act* that would otherwise be stranded in accumulated other comprehensive income. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted. The Company early adopted the standard in Q2 2018 and elected to not reclassify tax effects resulting from the *US Tax Cuts and Jobs Act* stranded in accumulated other comprehensive income to retained earnings as amounts were not material. Emera utilizes a portfolio approach to determine the timing and extent to which stranded income tax effects from items that were previously recorded in accumulated other comprehensive income are released.

REVENUE FROM CONTRACTS WITH CUSTOMERS

On January 1, 2018, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers* and all the related amendments, which created a new, principle-based revenue recognition framework. The standard has been codified as Accounting Standards Codification ("ASC") Topic 606. 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 requires additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company adopted ASC 606 using the modified retrospective method. Results for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting practices. The adoption of ASC 606 resulted in no adjustments to the Company's opening retained earnings as of the adoption date. The impact of the adoption of the new standard was immaterial to the Company's net income and is expected to be immaterial on an ongoing basis.

RECOGNITION AND MEASUREMENT OF FINANCIAL ASSETS AND FINANCIAL LIABILITIES

On January 1, 2018, the Company adopted ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities* and all of the related amendments. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The standard requires investments in equity securities, except those accounted for under the equity method of accounting or those that result in consolidation, to be measured at fair value. The Company has elected to measure equity securities that do not have a readily determinable fair value at cost minus impairment (if any), plus or minus observable price changes resulting from transactions for the identical or similar investments of the same issuer. The standard eliminates the available-for-sale classification for equity investments that recognized changes in the fair value as a component of other comprehensive income, resulting in all changes in fair value being recognized in net income. The impact as a result of the remeasurement of equity investments is expected to be immaterial to the Company's net income on an ongoing basis. A cumulative-effect adjustment of $4 million was made which increased retained earnings in the Consolidated Balance Sheet as of January 1, 2018.

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 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and is required to be applied prospectively. The Company adopted ASU 2017-01 effective January 1, 2018. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

IMPROVING THE PRESENTATION OF NET PERIODIC PENSION COST AND NET PERIODIC POSTRETIREMENT BENEFIT COST

In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The guidance requires the service cost component of defined benefit pension or other postretirement benefit plans to be reported in the same line items as other compensation costs. The other components of net benefit cost are required to be presented in the Consolidated Statements of Income outside of income from operations. Only the service cost component is eligible for capitalization as property, plant and equipment under this guidance. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The guidance is required to be applied retrospectively for presentation in the Consolidated Statements of Income and prospectively for the guidance around capitalization.

The Company adopted ASU 2017-07 effective January 1, 2018 and December 31, 2017 balances have been retrospectively restated in the Consolidated Statements of Income. The standard allows the Company to use the amounts disclosed in its pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements. This change resulted in $27 million of costs, previously presented within "Operating, maintenance and general", being reclassified to "Other income (expense), net" in the Consolidated Statements of Income for the year ended December 31, 2017.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the FASB. The following updates have been issued by the 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 an insignificant impact on the 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 previous guidance, operating leases are not recorded as assets and 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 will not early adopt the standard.

In January 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The Company will make this election. In July 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The Company will make this election. Additionally, the Company will elect the options that allow the Company to not reassess whether any expired or existing contracts contain leases, carry forward existing lease classification, use hindsight to determine the lease term for existing leases and not separate lease components from non-lease components for all lessee and lessor arrangements.

Over the past several years, the Company developed and executed a project plan which included holding training sessions with key stakeholders throughout the organization, gathering detailed information on existing lease arrangements, evaluating implementation alternatives and calculating the lease asset and liability balances associated with individual contractual arrangements. The Company has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. Updates to systems are not required as a result of implementation of this standard. The adoption of this standard will affect the Company's financial position by increasing assets and liabilities related to operating leases by approximately $70 million, with no impact to the Company's Consolidated Statements of Income. There will be no significant changes to the Company's accounting for lessor arrangements as a result of the adoption of the standard. The Company is in the process of assessing the disclosure requirements and continues to monitor FASB amendments to ASC Topic 842.

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.

TARGETED IMPROVEMENTS TO ACCOUNTING FOR HEDGING ACTIVITIES

In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted, and is required to be applied using a modified retrospective approach. The adoption of this standard will have no impact on the Company's consolidated financial statements.

CLOUD COMPUTING

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company is currently evaluating the transition methods and the impact of the adoption of this standard on the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q4 2018**	**Q3 2018**	**Q2 2018**	**Q1 2018**	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Operating revenues	**$ 1,799**	**$ 1,495**	**$ 1,423**	**$ 1,807**	$ 1,473	$ 1,427	$ 1,469	$ 1,857
Net income (loss) attributable to common shareholders	**231**	**118**	**90**	**271**	(228)	81	101	312
Adjusted net income attributable to common shareholders	**167**	**191**	**111**	**202**	137	118	117	152
Earnings per common share – basic	**0.98**	**0.51**	**0.38**	**1.17**	(1.06)	0.38	0.47	1.48
Earnings per common share – diluted	**0.98**	**0.50**	**0.38**	**1.17**	(1.06)	0.38	0.47	1.47
Adjusted earnings per common share – basic	**0.71**	**0.82**	**0.48**	**0.87**	0.64	0.55	0.55	0.72

Quarterly operating revenues and adjusted net income attributable to common shareholders are affected by seasonality. The first quarter provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. 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 also be affected by items outlined in the "Significant Items Affecting Earnings" section and mark-to-market adjustments.

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 and with the standards of the Public Company Accounting Oversight Board. Ernst & Young LLP has full and free access to the Audit Committee.

February 15, 2019

Scott Balfour
President and Chief Executive Officer

Gregory Blunden
Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the consolidated balance sheets as at December 31, 2018 and 2017, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018 and 2017, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's report thereon, in the Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, 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.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

Ernst + Young LLP

Ernst & Young LLP

Halifax, Canada
February 15, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Emera Incorporated

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of Emera Incorporated (the "Company") as of December 31, 2018, the related consolidated statement of income, consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, and the related notes and schedules (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2018, and the consolidated results of its operations and its consolidated cash flows for the year then ended, in conformity with United States generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

Ernst & Young LLP

Ernst & Young LLP
We have served as the Company's auditor since 1998.

Halifax, Canada
February 15, 2019

Emera Incorporated

CONSOLIDATED STATEMENTS OF INCOME

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 **2018**	 2017
Operating revenues		
Regulated electric	**$ 4,852**	$ 4,721
Regulated gas	**1,044**	1,002
Non-regulated	**628**	503
Total operating revenues (note 5)	**6,524**	6,226
Operating expenses		
Regulated fuel for generation and purchased power	**1,677**	1,638
Regulated cost of natural gas	**388**	379
Non-regulated fuel for generation and purchased power	**225**	209
Non-regulated direct costs	**16**	28
Operating, maintenance and general	**1,564**	1,372
Provincial, state, and municipal taxes	**340**	326
Depreciation and amortization	**916**	856
Total operating expenses	**5,126**	4,808
Income from operations	**1,398**	1,418
Income from equity investments (note 6)	**154**	124
Other expenses, net	**23**	25
Interest expense, net	**713**	698
Income before provision for income taxes	**816**	819
Income tax expense (note 7)	**69**	520
Net income	**747**	299
Non-controlling interest in subsidiaries	**1**	5
Preferred stock dividends	**36**	28
Net income attributable to common shareholders	**$ 710**	$ 266
Weighted average shares of common stock outstanding (in millions) (note 9)		
Basic	**233**	213
Diluted	**234**	214
Earnings per common share (note 9)		
Basic	**$ 3.05**	$ 1.25
Diluted	**$ 3.04**	$ 1.24
Dividends per common share declared	**$ 2.2825**	$ 2.1325

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

Emera Incorporated

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the millions of Canadian dollars	Year ended December 31 **2018**	 2017
Net income	**$ 747**	$ 299
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment	**627**	(464)
Unrealized gains (losses) on net investment hedges (1) (2)	**(122)**	97
Cash flow hedges		
Net derivative gains (losses)	**2**	10
Less: reclassification adjustment for losses (gains) included in income (3)	**(6)**	8
Net effects of cash flow hedges	**(4)**	18
Unrealized gains on available-for-sale investment		
Unrealized gain (loss) arising during the period	**–**	5
Less: reclassification adjustment for (gains) recognized in income	**(4)**	(1)
Net unrealized holding gains (losses)	**(4)**	4
Net change in unrecognized pension and post-retirement benefit obligation (4)	**9**	40
Other comprehensive income (loss) (5)	**506**	(305)
Comprehensive income (loss)	**1,253**	(6)
Comprehensive income (loss) attributable to non-controlling interest	**4**	–
Comprehensive Income (loss) of Emera Incorporated	**$ 1,249**	$ (6)

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

(1) 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.
(2) Net of tax recovery of $9 million (2017 – $9 million tax expense) for the year ended December 31, 2018.
(3) Net of tax recovery of nil (2017 – $1 million tax recovery) for the year ended December 31, 2018.
(4) Net of tax recovery of $2 million (2017 – $4 million tax recovery) for the year ended December 31, 2018.
(5) Net of tax recovery of $11 million (2017 – $4 million tax expense) for the year ended December 31, 2018.

Emera Incorporated

CONSOLIDATED BALANCE SHEETS

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Assets		
Current assets		
Cash and cash equivalents	**$ 316**	$ 438
Restricted cash (note 1)	**56**	65
Inventory (note 11)	**474**	418
Derivative instruments (notes 12 and 13)	**148**	141
Regulatory assets (note 14)	**165**	138
Receivables and other current assets (note 16)	**1,620**	1,326
Assets held for sale (note 17)	**53**	–
	2,832	2,526
Property, plant and equipment, net of accumulated depreciation and amortization of $8,567 and $7,824, respectively (note 18)	**18,712**	16,995
Other assets		
Deferred income taxes (note 7)	**175**	138
Derivative instruments (notes 12 and 13)	**19**	112
Regulatory assets (note 14)	**1,404**	1,273
Net investment in direct financing lease (note 20)	**475**	481
Investments subject to significant influence (note 6)	**1,316**	1,215
Goodwill (note 21)	**6,313**	5,805
Other long-term assets	**291**	261
Assets held for sale (note 17)	**777**	–
	10,770	9,285
Total assets	**$ 32,314**	$ 28,806

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

Emera Incorporated

CONSOLIDATED BALANCE SHEETS (continued)

As at millions of Canadian dollars	December 31 2018	December 31 2017
Liabilities and Equity		
Current liabilities		
Short-term debt (note 22)	**$ 1,186**	$ 1,241
Current portion of long-term debt (note 24)	**1,119**	741
Accounts payable	**1,289**	1,161
Derivative instruments (notes 12 and 13)	**260**	227
Regulatory liabilities (note 14)	**251**	226
Other current liabilities (note 23)	**428**	350
Liabilities associated with assets held for sale (note 17)	**20**	–
	4,553	3,946
Long-term liabilities		
Long-term debt (note 24)	**14,292**	13,140
Deferred income taxes (note 7)	**1,320**	1,023
Derivative instruments (notes 12 and 13)	**105**	83
Regulatory liabilities (note 14)	**2,359**	2,242
Pension and post-retirement liabilities (note 19)	**641**	559
Other long-term liabilities (note 6 and 25)	**686**	609
	19,403	17,656
Commitments and contingencies (note 26)		
Equity		
Common stock (note 8)	**5,816**	5,601
Cumulative preferred stock (note 27)	**1,004**	709
Contributed surplus	**84**	76
Accumulated other comprehensive income (loss) (note 10)	**338**	(165)
Retained earnings	**1,075**	891
Total Emera Incorporated equity	**8,317**	7,112
Non-controlling interest in subsidiaries (note 28)	**41**	92
Total equity	**8,358**	7,204
Total liabilities and equity	**$ 32,314**	$ 28,806

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

Scott Balfour
President and Chief Executive Officer

Emera Incorporated

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Year ended December 31 **2018**	2017
Operating activities		
Net income	**$ 747**	$ 299
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**928**	851
Income from equity investments, net of dividends	**(75)**	(90)
Allowance for equity funds used during construction	**(19)**	(9)
Deferred income taxes, net (1)	**185**	469
Net change in pension and post-retirement liabilities	**11**	(12)
Regulated fuel adjustment mechanism	**(16)**	68
Net change in fair value of derivative instruments	**55**	(157)
Net change in regulatory assets and liabilities (2)	**51**	(237)
Net change in capitalized transportation capacity	**(105)**	84
Other operating activities, net	**44**	31
Changes in non-cash working capital (note 29)	**(116)**	(104)
Net cash provided by operating activities	**1,690**	1,193
Investing activities		
Additions to property, plant and equipment	**(2,162)**	(1,529)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(49)**	(213)
Other investing activities	**21**	(19)
Net cash used in investing activities	**(2,190)**	(1,761)
Financing activities		
Change in short-term debt, net	**99**	(31)
Proceeds from short-term debt with maturities greater than 90 days	**129**	383
Repayment of short-term debt with maturities greater than 90 days	**(390)**	–
Proceeds from long-term debt, net of issuance costs	**1,055**	129
Retirement of long-term debt	**(757)**	(453)
Net borrowings (repayments) under committed credit facilities	**321**	230
Issuance of common stock, net of issuance costs	**10**	682
Issuance of preferred stock, net of issuance costs (note 27)	**291**	–
Dividends on common stock	**(346)**	(287)
Dividends on preferred stock	**(36)**	(28)
Other financing activities	**(32)**	(32)
Net cash provided by financing activities	**344**	593
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**25**	(13)
Net increase (decrease) in cash, cash equivalents, and restricted cash	**(131)**	12
Cash, cash equivalents, and restricted cash, beginning of year	**503**	491
Cash, cash equivalents and restricted cash, end of year	**372**	503
Cash, cash equivalents, and restricted cash consists of:		
Cash	**273**	216
Short-term investments	**43**	222
Restricted cash	**56**	65
Cash, cash equivalents, and restricted cash	**372**	503

(1) 2017 includes $317 million for the revaluation of US non-regulated net deferred income tax assets as a result of US tax reform.
(2) 2017 includes the net impact of the change in deferred taxes as a result of US tax reform with an offset to a regulatory liability of $1.1 billion.

Supplementary Information to Consolidated Statements of Cash Flows (note 29)

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

Emera Incorporated

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) (1)	Retained Earnings	Non-Controlling Interest	Total Equity
Balance, December 31, 2017	**$ 5,601**	**$ 709**	**$ 76**	**$ (165)**	**$ 891**	**$ 92**	**$ 7,204**
Net income	**–**	**–**	**–**	**–**	**746**	**1**	**747**
Other comprehensive income, net of tax recovery of $11 million	**–**	**–**	**–**	**503**	**–**	**3**	**506**
Issuance of preferred stock, net of after-tax issuance costs	**–**	**295**	**–**	**–**	**–**	**–**	**295**
Dividends declared on preferred stock (note 27)	**–**	**–**	**–**	**–**	**(36)**	**–**	**(36)**
Dividends declared on common stock ($2.2825/share)	**–**	**–**	**–**	**–**	**(528)**	**–**	**(528)**
Common stock issued under purchase plan	**191**	**–**	**–**	**–**	**–**	**–**	**191**
Acquisition of non-controlling interest of ICD Utilities Limited ("ICDU")	**22**	**–**	**6**	**–**	**–**	**(53)**	**(25)**
Other	**2**	**–**	**2**	**–**	**2**	**(2)**	**4**
Balance, December 31, 2018	**$ 5,816**	**$ 1,004**	**$ 84**	**$ 338**	**$ 1,075**	**$ 41**	**$ 8,358**
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 135	$ 1,076	$ 112	$ 6,845
Net income	–	–	–	–	294	5	299
Other comprehensive income (loss), net of tax expense of $4 million	–	–	–	(300)	–	(5)	(305)
Issuance of common stock, net of after-tax issuance costs	686	–	–	–	–	–	686
Dividends declared on preferred stock (note 27)	–	–	–	–	(28)	–	(28)
Dividends declared on common stock ($2.1325/share)	–	–	–	–	(451)	–	(451)
Common stock issued under purchase plan	173	–	–	–	–	–	173
Stock-based compensation	3	–	1	–	–	–	4
Repurchase of preferred shares of GBPC (note 28)	–	–	–	–	–	(14)	(14)
Other	1	–	–	–	–	(6)	(5)
Balance, December 31, 2017	$ 5,601	$ 709	$ 76	$ (165)	$ 891	$ 92	$ 7,204

(1) Accumulated Other Comprehensive Income (Loss) ("AOCI") ("AOCL").

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

Emera Incorporated

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2018 and 2017

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

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

At December 31, 2018, Emera's primary rate-regulated subsidiaries and investments 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 that include:
  - Tampa Electric Company ("TEC"), which holds the Tampa Electric Division ("Tampa Electric"), a vertically integrated regulated electric utility, serving approximately 764,000 customers in West Central Florida, and Peoples Gas System Division ("PGS"), a regulated gas distribution utility, serving approximately 392,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 530,000 customers across New Mexico;
  - TECO Finance, Inc. ("TECO Finance"), a financing subsidiary of TECO Energy; and
  - SeaCoast Gas Transmission LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida.
- Nova Scotia Power Inc. ("NSPI"), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 519,000 customers;
- Emera Maine, a regulated electric transmission and distribution utility, serving approximately 159,000 customers in the state of Maine;
- Emera Caribbean represents Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
  - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados, serving approximately 130,000 customers;
  - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated utility operating on Grand Bahama Island, serving approximately 19,000 customers. On January 15, 2018, Emera completed the acquisition of the minority shareholder common shares for total consideration of $35 million USD, increasing Emera's interest in GBPC from 80.4 per cent to 100 per cent;
  - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), a vertically integrated utility on the island of Dominica, serving approximately 26,000 customers; and
  - a 19.1 per cent indirect interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas ("LNG") from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy Canada, which expires in 2034;

- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), consisting of two transmission investments related to an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador being developed by Nalcor Energy and forecasted 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 developed the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre subsea cables, connecting the island of Newfoundland and Nova Scotia. This project went in service on January 15, 2018; and
  - a 49.5 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and the energization phase of the project began in June 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.

At December 31, 2018, Emera's investments in other energy-related non-regulated companies included the following:

- Emera Energy, which consists of:
  - 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" or "NEGG"), 1,115 MW of combined-cycle gas-fired electricity generating capacity in the northeastern United States. On November 26, 2018, Emera announced an agreement to sell its NEGG facilities. The transaction is expected to close in the first quarter of 2019. Refer to note 17 for additional information;
  - 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 northwestern 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;
- Emera US Holdings Inc., 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; 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 Company performs ongoing analysis to assess whether it holds any VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. 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.

Intercompany balances and intercompany 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 ("OM&G"), 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 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. The rates are designed to recover the costs of providing the regulated products or services and provide a reasonable rate of return on the equity invested or assets as applicable (refer to note 14 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 foreign operations whose functional currency is not the Canadian dollar are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average exchange rate in effect 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 dollar 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

Regulated Electric Revenue

Electric revenues, including energy charges, demand charges, basic facilities charges and applicable clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the electricity. Electric revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the respective regulator and recorded based on metered usage, which occur on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of megawatt hour ("MWh") delivered to customers at the established rate expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

Regulated Gas Revenue

Gas revenues, including energy charges, demand charges, basic facilities charges and applicable clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when gas is delivered to customers over time as the customer simultaneously receives and consumes the benefits of the gas. Gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the distribution and sale of gas are recognized at rates approved by the respective regulator and recorded based on metered usage, which occur on a periodic, systematic basis, generally monthly. At the end of each reporting period, the gas delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the number of therms delivered to customers at the established rate expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of usage, weather, and inter-period changes to customer classes.

Direct Finance Lease

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.

Non-regulated Revenue

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 revenues. Revenues are recorded when obligations under terms of a contract are satisfied and are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

Energy sales are recognized when obligations under the terms of the contracts are satisfied, which is when electricity is delivered to customers over time.

Capacity payments are recognized when obligations under the terms of a contract are satisfied, which is as the plants stand ready to deliver electricity to customers. Revenues related to capacity payments are recognized at rates determined through an auction process held annually, three years in advance, through the forward capacity market.

Other non-regulated revenues are recorded when obligations under terms of a contract are satisfied.

Other

Sales, value add, and other taxes, with the exception of gross receipts taxes discussed below, collected by the Company concurrent with revenue-producing activities are excluded from revenue.

FRANCHISE FEES AND GROSS RECEIPTS

Tampa Electric and PGS 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 "Regulated electric" and "Regulated gas" 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 Statements of Income.

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. For some of Emera's rate regulated subsidiaries depreciation is calculated using the group remaining life method which is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property. The service lives of regulated assets require the appropriate regulatory approval.

Intangible assets, which are included in "Property, plant and equipment" 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. For some of Emera's rate regulated subsidiaries, amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above. The service lives of regulated intangible assets require 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 and is adjusted for the impact of foreign exchange. Under the applicable accounting guidance, goodwill is subject to an annual assessment for impairment at the reporting unit level. Refer to note 21 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 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 Tampa Electric, PGS, NMGC and Emera Maine on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by the 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. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are 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 classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. Refer to note 7 for further details.

DERIVATIVES AND HEDGING ACTIVITIES

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange, interest rates and share prices 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, equity derivatives, 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 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. 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 any changes in fair value are 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. 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 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, with changes in fair value 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, operating maintenance and general and 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 and other current assets" and obligations to return cash collateral are recognized in "Accounts payable".

CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. Total short-term investments of $43 million have an effective interest rate of 2.0 per cent at December 31, 2018 (2017 – $222 million with an effective interest rate of 1.4 per cent).

Included in restricted cash are funds required to be set aside for the BLPC Self-Insurance Fund ("SIF") (note 31).

RECEIVABLES AND ALLOWANCE FOR DOUBTFUL ACCOUNTS

Utility 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

Long-Lived Assets

Emera assesses whether there has been an impairment of long-lived assets and intangibles 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. 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 outside of this annual analysis.

The review of long-lived assets for impairment involves comparing the undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated fair value. 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.

Goodwill

Goodwill is not amortized, but 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. In performing a qualitative assessment management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

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 chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test 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, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Management estimates the fair value of the reporting unit by using the income approach or a combination of the income and market approach. The income approach is applied using a discounted cash flow analysis which relies on management's best estimate of the reporting units' projected cash flows. The analysis 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 used 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. When using the market approach, management estimates fair value based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the fair value include discount and growth rates, rate case assumptions, valuation of Emera's net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows and the fair value of debt. Adverse changes in assumptions described above could result in a future material impairment of the goodwill assigned to Emera's reporting units with goodwill.

Emera reviews recorded goodwill at least annually (during the fourth quarter) for each reporting unit to which goodwill has been allocated, with interim impairment tests performed when impairment indicators are present. No impairment provisions were required for either 2018 or 2017. Refer to note 21 for further detail.

Equity Method Investments

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the fair value 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

Equity investments, other than those accounted for under the equity method of accounting, are measured at fair value with changes in fair value recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable fair values are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments.

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. AROs are included in "Other long-term liabilities" and accretion expense is included as part of "Depreciation and amortization". Any regulated accretion expense not yet approved by the regulator is recorded in "Property, plant and equipment" and included in the next depreciation study.

As at December 31, 2018 and 2017, some of the Company's transmission and distribution assets may have conditional ARO's which are not recognized in the consolidated financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. 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 in the period in which an amount can be determined.

COST OF REMOVAL

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO costs of removal represent funds received from customers through depreciation rates to cover estimated 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.

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 initially 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 adopted by the Company in 2018, are described as follows:

RECLASSIFICATION OF CERTAIN TAX EFFECTS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

In February 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Updates ("ASU") No. 2018-02, *Income Statement – Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The standard allows reclassification from accumulated other comprehensive income to retained earnings for certain tax effects resulting from the *US Tax Cuts and Jobs Act* that would otherwise be stranded in accumulated other comprehensive income. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted. The Company early adopted the standard in Q2 2018 and elected to not reclassify tax effects resulting from the *US Tax Cuts and Jobs Act* stranded in accumulated other comprehensive income to retained earnings as amounts were not material. Emera utilizes a portfolio approach to determine the timing and extent to which stranded income tax effects from items that were previously recorded in accumulated other comprehensive income are released.

REVENUE FROM CONTRACTS WITH CUSTOMERS

On January 1, 2018, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers* and all the related amendments, which created a new, principle-based revenue recognition framework. The standard has been codified as Accounting Standards Codification ("ASC") Topic 606. 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 requires additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company adopted ASC 606 using the modified retrospective method. Results for reporting periods beginning after January 1, 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting practices. The adoption of ASC 606 resulted in no adjustments to the Company's opening retained earnings as of the adoption date. The impact of the adoption of the new standard was immaterial to the Company's net income and is expected to be immaterial on an ongoing basis.

RECOGNITION AND MEASUREMENT OF FINANCIAL ASSETS AND FINANCIAL LIABILITIES

On January 1, 2018, the Company adopted ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities* and all of the related amendments. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The standard requires investments in equity securities, except those accounted for under the equity method of accounting or those that result in consolidation, to be measured at fair value. The Company has elected to measure equity securities that do not have a readily determinable fair value at cost minus impairment (if any), plus or minus observable price changes resulting from transactions for the identical or similar investments of the same issuer. The standard eliminates the available-for-sale classification for equity investments that recognized changes in the fair value as a component of other comprehensive income, resulting in all changes in fair value being recognized in net income. The impact as a result of the remeasurement of equity investments is expected to be immaterial to the Company's net income on an ongoing basis. A cumulative-effect adjustment of $4 million was made which increased retained earnings in the Consolidated Balance Sheet as of January 1, 2018.

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 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and is required to be applied prospectively. The Company adopted ASU 2017-01 effective January 1, 2018. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

IMPROVING THE PRESENTATION OF NET PERIODIC PENSION COST AND NET PERIODIC POSTRETIREMENT BENEFIT COST

In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The guidance requires the service cost component of defined benefit pension or other postretirement benefit plans to be reported in the same line items as other compensation costs. The other components of net benefit cost are required to be presented in the Consolidated Statements of Income outside of income from operations. Only the service cost component is eligible for capitalization as property, plant and equipment under this guidance. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The guidance is required to be applied retrospectively for presentation in the Consolidated Statements of Income and prospectively for the guidance around capitalization.

The Company adopted ASU 2017-07 effective January 1, 2018 and December 31, 2017 balances have been retrospectively restated in the Consolidated Statements of Income. The standard allows the Company to use the amounts disclosed in its pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements. This change resulted in $27 million of costs, previously presented within "Operating, maintenance and general", being reclassified to "Other income (expense), net" in the Consolidated Statements of Income for the year ended December 31, 2017.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the FASB. The following updates have been issued by the 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 an insignificant impact on the 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 previous guidance, operating leases are not recorded as assets and 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 will not early adopt the standard.

In January 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The Company will make this election. In July 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The Company will make this election. Additionally, the Company will elect the options that allow the Company to not reassess whether any expired or existing contracts contain leases, carry forward existing lease classification, use hindsight to determine the lease term for existing leases and not separate lease components from non-lease components for all lessee and lessor arrangements.

Over the past several years, the Company developed and executed a project plan which included holding training sessions with key stakeholders throughout the organization, gathering detailed information on existing lease arrangements, evaluating implementation alternatives and calculating the lease asset and liability balances associated with individual contractual arrangements. The Company has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. Updates to systems are not required as a result of implementation of this standard. The adoption of this standard will affect the Company's financial position by increasing assets and liabilities related to operating leases by approximately $70 million, with no impact to the Company's Consolidated Statements of Income. There will be no significant changes to the Company's accounting for lessor arrangements as a result of the adoption of the standard. The Company is in the process of assessing the disclosure requirements and continues to monitor FASB amendments to ASC Topic 842.

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.

TARGETED IMPROVEMENTS TO ACCOUNTING FOR HEDGING ACTIVITIES

In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted, and is required to be applied using a modified retrospective approach. The adoption of this standard will have no impact on the Company's consolidated financial statements.

CLOUD COMPUTING

In August 2018, the FASB issued ASU 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company is currently evaluating the transition methods and the impact of the adoption of this standard on the consolidated financial statements.

4. 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. Emera's six reportable segments are Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other (includes Emera Utility Services, ENL, Emera Brunswick Pipeline, Corporate, other strategic investments and certain holding companies). The Company is reviewing its internal reporting to the chief operating decision maker and considering changes to its reportable segments for 2019.

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2018								
Operating revenues from external customers (1)	**$ 3,675**	**$ 1,437**	**$ 278**	**$ 467**	**$ 600**	**$ 68**	**$ –**	**$ 6,525**
Inter-segment revenues (1)	**–**	**3**	**–**	**–**	**14**	**36**	**(54)**	**(1)**
Total operating revenues	**3,675**	**1,440**	**278**	**467**	**614**	**104**	**(54)**	**6,524**
AFUDC – debt and equity	**21**	**6**	**3**	**–**	**–**	**–**	**–**	**30**
Regulated fuel and fixed cost deferral adjustments	**–**	**(46)**	**–**	**–**	**–**	**–**	**–**	**(46)**
Depreciation and amortization	**534**	**219**	**64**	**50**	**46**	**3**	**–**	**916**
Interest expense (2)	**238**	**142**	**22**	**27**	**5**	**290**	**–**	**724**
Internally allocated interest (3)	**–**	**–**	**–**	**–**	**(24)**	**24**	**–**	**–**
Income from equity investments	**–**	**–**	**3**	**3**	**38**	**110**	**–**	**154**
Income tax expense (recovery)	**101**	**8**	**11**	**(2)**	**66**	**(115)**	**–**	**69**
Net income attributable to common shareholders	**428**	**131**	**44**	**41**	**165**	**(99)**	**–**	**710**
Capital expenditures	**1,548**	**345**	**100**	**87**	**33**	**38**	**–**	**2,151**
As at December 31, 2018								
Total assets	**20,051**	**5,143**	**1,721**	**1,373**	**1,785**	**2,275**	**(34)**	**32,314**
Investments subject to significant influence (4)	**–**	**–**	**35**	**42**	**–**	**1,239**	**–**	**1,316**
Goodwill	**6,053**	**–**	**156**	**104**	**–**	**–**	**–**	**6,313**

(1) All significant intercompany balances and intercompany transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Intercompany 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) Interest expense is net of interest revenue. Corporate and Other Interest expense has also been reduced by amortization of $12 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.

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

(4) Emera Energy's segment includes an investment in Bear Swamp. At December 31, 2018 this investment is in a credit position of $172 million and is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2017								
Operating revenues from external customers (1)	$ 3,623	$ 1,335	$ 297	$ 434	$ 451	$ 86	$ –	$ 6,226
Inter-segment revenues (1)	–	3	–	–	14	41	(58)	–
Total operating revenues	3,623	1,338	297	434	465	127	(58)	6,226
AFUDC – debt and equity	5	8	3	–	–	–	–	16
Regulated fuel and fixed cost deferral adjustments	–	59	–	–	–	–	–	59
Depreciation and amortization	500	207	47	51	48	3	–	856
Interest expense (2)	248	134	20	25	2	276	–	705
Internally allocated interest (3)	–	–	–	–	(24)	24	–	–
Income from equity investments	–	–	1	3	24	96	–	124
Income tax expense (recovery)	529	–	27	–	18	(54)	–	520
Net income attributable to common shareholders	99	129	46	31	93	(132)	–	266
Capital expenditures	910	385	82	72	47	26	–	1,522
As at December 31, 2017								
Total assets	17,216	4,979	1,540	1,251	1,575	2,331	(86)	28,806
Investments subject to significant influence (4)	–	–	13	39	–	1,163	–	1,215
Goodwill	5,566	–	143	96	–	–	–	5,805

(1) All significant intercompany balances and intercompany transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Intercompany 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) Interest expense is net of interest revenue. Corporate and Other Interest expense has also been reduced by amortization of $24 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.
(3) Segment net income is reported on a basis that includes internally allocated financing costs.
(4) Emera Energy's segment includes an investment in Bear Swamp. At December 31, 2017 this investment is in a credit position of $188 million and is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

GEOGRAPHICAL INFORMATION

Revenues (1):

For the	Year ended December 31	
millions of Canadian dollars	**2018**	2017
Canada	**$ 1,520**	$ 1,464
United States	**4,537**	4,328
Barbados	**319**	280
The Bahamas	**121**	119
Dominica	**27**	35
	$ 6,524	$ 6,226

(1) Revenues are based on country of origin of the product or service sold.

Property Plant and Equipment:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Canada	**$ 4,128**	$ 3,995
United States	**13,739**	12,257
Barbados	**446**	408
The Bahamas	**315**	276
Dominica	**84**	59
	$ 18,712	$ 16,995

5. REVENUE

The following disaggregates the Company's revenue by major source:

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2018								
Regulated								
Electric Revenue								
Residential	$ 1,384	$ 731	$ 107	$ 154	$ –	$ –	$ –	$ 2,376
Commercial	755	405	80	270	–	–	–	1,510
Industrial	209	233	16	30	–	–	–	488
Other electric and regulatory deferrals	312	43	9	7	–	–	–	371
Other (1)	10	28	66	6	–	–	(3)	107
Regulated electric revenue	2,670	1,440	278	467	–	–	(3)	4,852
Gas Revenue								
Residential	492	–	–	–	–	–	–	492
Commercial	291	–	–	–	–	–	–	291
Industrial	49	–	–	–	–	–	–	49
Finance income (2) (3)	–	–	–	–	–	57	–	57
Other	155	–	–	–	–	–	–	155
Regulated gas revenue	987	–	–	–	–	57	–	1,044
Non-Regulated								
Marketing and trading margin (4)	–	–	–	–	115	–	–	115
Energy sales (4)	–	–	–	–	309	–	(16)	293
Capacity	–	–	–	–	136	–	–	136
Other	18	–	–	–	–	47	(35)	30
Mark-to-market (3)	–	–	–	–	54	–	–	54
Non-regulated revenue	18	–	–	–	614	47	(51)	628
Total operating revenues	**$ 3,675**	**$ 1,440**	**$ 278**	**$ 467**	**$ 614**	**$ 104**	**$ (54)**	**$ 6,524**

(1) Other includes an immaterial amount of rental revenues, which do not represent revenue from contracts with customers.
(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.
(3) Revenue which does not represent revenues from contracts with customers.
(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations

Remaining performance obligations primarily represent gas transportation contracts, lighting contracts and long-term steam supply arrangements with fixed contract terms. As of December 31, 2018, the aggregate amount of the transaction price allocated to remaining performance obligations was $370 million. As allowed by the practical expedient in ASC 606, this amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2033.

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

millions of Canadian dollars	Carrying Value As at December 31		Equity Income For the year ended December 31		Percentage of Ownership
	2018	2017	**2018**	2017	**2018**
NSPML	**$ 545**	$ 510	**$ 45**	$ 36	**100.0**
LIL (1)	**534**	492	**42**	37	**49.5**
M&NP (2)	**155**	156	**22**	23	**12.9**
Lucelec (2)	**42**	39	**3**	3	**19.1**
Bear Swamp (3)	**–**	–	**38**	23	**50.0**
Other Investments	**40**	18	**4**	2	
	$ 1,316	$ 1,215	**$ 154**	$ 124	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued. 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 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.

(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.

(3) 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 $172 million (2017 – $188 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a $12 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 31). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Balance Sheets		
Current assets	**$ 86**	$ 225
Property, plant and equipment	**1,690**	1,720
Non-current assets	**140**	74
Total assets	**$ 1,916**	$ 2,019
Current liabilities	**$ 21**	$ 180
Long-term debt	**1,288**	1,287
Non-current liabilities	**62**	42
Equity	**545**	510
Total liabilities and equity	**$ 1,916**	$ 2,019

7. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and Nova Scotia and New Brunswick provincial statutory income tax rate for the following reasons:

millions of Canadian dollars		2018		2017
Income before provision for income taxes	**$**	**816**	$	819
Statutory income tax rate		**31%**		31%
Income taxes, at statutory income tax rate		**253**		254
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(59)**		(54)
Foreign tax rate variance		**(55)**		36
Amortization of deferred income tax regulatory liabilities		**(37)**		–
Florida state tax apportionment adjustment		**(23)**		–
Tax effect of equity earnings		**(15)**		(12)
Financing deductions		**(4)**		(17)
Revaluation of US non-regulated deferred income taxes due to tax reform		**–**		317
Other		**9**		(4)
Income tax expense (recovery)	**$**	**69**	$	520
Effective income tax rate		**8%**		63%

On December 22, 2017, the *US Tax Cuts and Jobs Act of 2017* ("the Act") was signed into law enacting a broad range of legislative changes including reduction of the US federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018, limitations on the deductibility of interest and 100 per cent expensing of qualified property. The Act provides an exemption to regulated electric and gas utilities from the limitations on the deductibility of interest and the 100 per cent expensing of qualified property.

At December 31, 2017, the Company was required to revalue its US deferred income tax assets and liabilities based on the new tax rate at the date of enactment. The Company recognized a $317 million income tax expense as a result of the revaluation of its US non-regulated net deferred income tax assets. The Company also reduced its US regulated net deferred income tax liabilities by $1.1 billion and recorded an equivalent regulatory liability since the benefit of lower US taxes is expected to be returned to customers over time as required by the Act or by order of the applicable regulator. The December 31, 2017 balances of deferred income tax assets and liabilities that were revalued were $1.3 billion and $1.8 billion, respectively.

No further adjustments were recognized in 2018 and the Company has completed its accounting for the revaluation of its US deferred income tax assets and liabilities resulting from the effects of the Act. The measurement period allowed by SEC Staff Accounting Bulletin 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* is now closed.

In Q4 2018, the Company reclassified $149 million of AMT credit carryforwards from deferred income tax assets to receivables and other current assets as it expects to receive the refund in 2019.

On November 26, 2018, the Internal Revenue Service ("IRS") issued proposed regulations on the interest deductibility limitation rules legislated under the Act. The Company believes its US based financing interest will be deductible under the Act.

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	2018	2017
Current income taxes		
Canada	$ 3	$ 24
United States	(121)	24
Other	2	3
Deferred income taxes		
Canada	11	3
United States	211	384
Other	(3)	(1)
Operating loss carryforwards		
Canada	(33)	(40)
United States	–	(194)
Other	(1)	–
Revaluation of US non-regulated deferred income taxes		
United States	–	317
Income tax expense (recovery)	$ 69	$ 520

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	2018	2017
Canada	$ 127	$ 88
United States	646	693
Other	43	38
Income before provision for income taxes	$ 816	$ 819

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	2018	2017
Deferred income tax assets:		
Tax loss carryforwards	$ 917	$ 853
Tax credit carryforwards	269	314
Regulatory liabilities – cost of removal	206	208
Pension and post-retirement liabilities	126	112
Derivative instruments	90	107
Other	441	394
Total deferred income tax assets before valuation allowance	2,049	1,988
Valuation allowance	(163)	(105)
Total deferred income tax assets after valuation allowance	$ 1,886	$ 1,883
Deferred income tax (liabilities):		
Property, plant and equipment	$ (2,591)	$ (2,321)
Derivative instruments	(124)	(155)
Other	(316)	(292)
Total deferred income tax liabilities	$ (3,031)	$ (2,768)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	$ 175	$ 138
Long-term deferred income tax liabilities	(1,320)	(1,023)
Net deferred income tax liabilities	$ (1,145)	$ (885)

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 certain loss carryforwards and unrealized capital losses on investments. A valuation allowance of $163 million has been recorded as at December 31, 2018 (2017 – $105 million) related to the loss carryforwards and investments.

Emera's net operating loss ("NOL"), capital loss and tax credit carryforwards and their expiration periods as at December 31, 2018 consisted of the following:

millions of Canadian dollars	Gross Tax Carryforwards	Unrecognized Amounts	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 817	$ (405)	$ 412	2027-2038
Capital loss	86	(77)	9	Indefinite
United States				
Federal NOL	$ 2,848	$ –	$ 2,848	2024-2037
State NOL	1,314	(47)	1,267	2024-2038
Capital loss	6	(6)	–	2019
Tax credit	268	–	268	2019-Indefinite
Other				
NOL	$ 34	$ (34)	$ –	2019-2025

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	**2018**	2017
Balance, January 1	**$ 19**	$ 18
Increases due to tax positions related to a prior year	**8**	–
Decreases due to tax positions related to a prior year	**(1)**	–
Increases due to tax positions related to current year	**–**	1
Balance, December 31	**$ 26**	$ 19

The total amount of unrecognized tax benefits as at December 31, 2018 was $26 million (2017 – $19 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $4 million (2017 – $1 million) with $3 million of interest expense recognized in the Consolidated Statement of Income (2017 – nil). 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 IRS 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 $1.4 billion as at December 31, 2018 (2017 – $822 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, 2018, 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 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 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.

8. COMMON STOCK

Authorized: Unlimited number of non-par value common shares.

	2018		2017	
Issued and outstanding:	millions of shares	millions of Canadian dollars	millions of shares	millions of Canadian dollars
Balance, December 31, 2017	**228.77**	**$ 5,601**	210.02	$ 4,738
Conversion of Convertible Debentures	**0.01**	**–**	0.15	6
Issuance of common stock (1)	**0.45**	**22**	14.61	680
Issued under Purchase Plans at market rate	**4.87**	**200**	3.89	182
Discount on shares purchased under Dividend Reinvestment Plan	**–**	**(9)**	–	(9)
Options exercised under senior management share option plan	**0.02**	**1**	0.10	3
Employee Share Purchase Plan	**–**	**1**	–	1
Balance, December 31, 2018	**234.12**	**$ 5,816**	228.77	$ 5,601

(1) In Q1 2018, Emera issued 0.45 million common shares to facilitate the creation and issuance of 1.8 million depository receipts in connection with the ICDU share acquisition. The depository receipts are listed on the Bahamas International Securities Exchange.

As at December 31, 2018, the following common shares were reserved for issuance: 6.5 million (2017 – 6.5 million) under the senior management stock option plan, 1.0 million (2017 – 1.3 million) under the employee common share purchase plan and 12.6 million (2017 – 4.2 million) under the dividend reinvestment plan ("DRIP").

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2018, Emera is in compliance with this requirement.

9. 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)	**2018**	2017
Numerator		
Net income attributable to common shareholders	**$ 709.6**	$ 266.1
Diluted numerator	**709.6**	266.1
Denominator		
Weighted average shares of common stock outstanding	**231.7**	212.3
Weighted average deferred share units outstanding	**1.3**	1.1
Weighted average shares of common stock outstanding – basic	**233.0**	213.4
Stock-based compensation	**0.4**	0.6
Convertible Debentures	**0.1**	0.1
Weighted average shares of common stock outstanding – diluted	**233.5**	214.1
Earnings per common share		
Basic	**$ 3.05**	$ 1.25
Diluted	**$ 3.04**	$ 1.24

10. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income are as follows:

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
Balance, January 1, 2018	**$ 30**	**$ 48**	**$ (3)**	**$ 3**	**$ (243)**	**$ (165)**
Other comprehensive income (loss) before reclassifications	**624**	**(122)**	**2**	**–**	**–**	**504**
Amounts reclassified from accumulated other comprehensive income loss	**–**	**–**	**(6)**	**(4)**	**9**	**(1)**
Net current period other comprehensive income (loss)	**624**	**(122)**	**(4)**	**(4)**	**9**	**503**
Balance, December 31, 2018	**$ 654**	**$ (74)**	**$ (7)**	**$ (1)**	**$ (234)**	**$ 338**
For the year ended December 31, 2017						
Balance, January 1, 2017 (1)	$ 489	$ (49)	$ (21)	$ (1)	$ (283)	$ 135
Other comprehensive income (loss) before reclassifications	(459)	97	10	5	–	(347)
Amounts reclassified from accumulated other comprehensive income loss (gain) (2)	–	–	8	(1)	40	47
Net current period other comprehensive income (loss)	(459)	97	18	4	40	(300)
Balance, December 31, 2017	$ 30	$ 48	$ (3)	$ 3	$ (243)	$ (165)

(1) The January 1, 2017 balance of AOCI and Regulatory Assets includes a prior period reclassification of $44 million in unrecognized pension and post-retirement benefit costs and $18 million in deferred taxes ($26 million, net of tax) to be consistent with current year presentation.

(2) Certain net changes in unrecognized pension and post-retirement benefit costs for Emera Maine of $4 million were previously presented as a change in AOCI and are now presented as a change in Regulatory Assets for the year ended December 31, 2017 to be consistent with current year presentation.

The reclassifications out of accumulated other comprehensive income (loss) are as follows:

For the		Year ended December 31	
millions of Canadian dollars		**2018**	2017
	Affected line item in the Consolidated Financial Statements		
Losses (gain) on derivatives recognized as cash flow hedges			
Power and gas swaps	Non-regulated fuel for generation and purchased power	**$ (1)**	$ (3)
Foreign exchange forwards	Operating revenue – regulated	**(5)**	10
Total before tax		**(6)**	7
	Income tax recovery (expense)	**–**	1
Total net of tax		**$ (6)**	$ 8
Net change in available-for-sale investments			
	Other income (expenses), net	**$ –**	$ (1)
	Retained earnings (1)	**(4)**	–
Total net of tax		**$ (4)**	$ (1)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	Operating, maintenance and general ("OM&G")	**$ 25**	$ 33
Past service costs (gains)	OM&G	**(1)**	(8)
Amounts reclassified into obligations	Pension and post-retirement benefits	**(17)**	11
Total before tax		**7**	36
	Income tax recovery (expense)	**2**	4
Total net of tax		**$ 9**	$ 40
Total reclassifications out of AOCI, net of tax, for the period		**$ (1)**	$ 47

(1) Related to the adoption of ASU 2016-01, Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities. Refer to note 2 for additional detail.

11. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Fuel	**$ 213**	$ 180
Materials	**241**	216
Emission credits (1)	**20**	22
	$ 474	$ 418

(1) The NEGG facilities are subject to the Acid Rain Program for sulphur dioxide emissions and the Regional Greenhouse Gas Initiative for carbon dioxide emissions. The emission credits inventory balance represents the credits purchased to offset the other current liabilities and other long-term liabilities associated with these programs.

12. DERIVATIVE INSTRUMENTS

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**December 31 2018**	December 31 2017	**December 31 2018**	December 31 2017
Cash flow hedges				
Power swaps	**$ -**	$ 5	**$ -**	$ 2
Foreign exchange forwards	**-**	2	**5**	5
	-	7	**5**	7
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**71**	137	**1**	10
Power purchases	**2**	5	**1**	3
Natural gas purchases and sales	**2**	6	**4**	7
Heavy fuel oil purchases	**1**	15	**1**	4
Foreign exchange forwards	**29**	32	**-**	4
	105	195	**7**	28
HFT derivatives				
Power swaps and physical contracts	**62**	125	**76**	162
Natural gas swaps, futures, forwards, physical contracts	**125**	105	**403**	294
	187	230	**479**	456
Other derivatives				
Interest rate swap	**1**	2	**-**	-
	1	2	**-**	-
Total gross current derivatives	**293**	434	**491**	491
Impact of master netting agreements with intent to settle net or simultaneously	**(126)**	(181)	**(126)**	(181)
	167	253	**365**	310
Current	**148**	141	**260**	227
Long-term	**19**	112	**105**	83
Total derivatives	**$ 167**	$ 253	**$ 365**	$ 310

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 millions of Canadian dollars	**December 31 2018**	December 31 2017	**December 31 2018**	December 31 2017
Regulatory deferral	**$ 1**	$ 14	**$ 1**	$ 14
HFT derivatives	**125**	167	**125**	167
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 126**	$ 181	**$ 126**	$ 181

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. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

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			**2018**			2017
	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	**$ 1**	**$ -**	**$ -**	$ 3	$ –	$ –
Realized gain (loss) in operating revenue – regulated	**-**	**-**	**5**	–	–	(10)
Total gains (losses) in Net income	**$ 1**	**$ -**	**$ 5**	$ 3	$ –	$ (10)

As at	Year ended December 31					
millions of Canadian dollars			**2018**			2017
	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	**$ (1)**	**$ -**	**$ (6)**	$ –	$ –	$ (3)

The Company expects $4 million of unrealized losses currently in AOCI to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at December 31, 2018, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2019	2020	2021
Foreign exchange forwards (USD) sales	$ 30	$ 30	$ –

REGULATORY DEFERRAL

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			**2018**			2017
	Commodity swaps and forwards	**Physical natural gas purchases and sales**	**Foreign exchange forwards**	Physical natural gas purchases and sales	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (34)**	**$ -**	**$ 4**	$ (33)	$ (1)	$ (4)
Unrealized gain (loss) in regulatory liabilities	**29**	**-**	**24**	83	1	(30)
Realized (gain) loss in regulatory liabilities	**(8)**	**-**	**-**	(2)	–	–
Realized (gain) loss in inventory (1)	**(55)**	**-**	**(18)**	(17)	–	(30)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(2)**	**-**	**(9)**	(3)	–	(14)
Total change derivative instruments	**$ (70)**	**$ -**	**$ 1**	$ 28	$ –	$ (78)

(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, 2018, 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:

millions	2019	2020–2023
	Purchases	Purchases
Coal (metric tonnes)	1	1
Natural Gas (Mmbtu)	16	–
Heavy fuel oil (bbls)	–	1

FOREIGN EXCHANGE SWAPS AND FORWARDS

As at December 31, 2018, 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:

	2019	2020
Foreign exchange contracts (millions of US dollars)	$ 121	$ 111
Weighted average rate	1.1621	1.3027
% of USD requirements	66%	48%

The Company reassesses foreign exchange forecasted 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 millions of Canadian dollars	Year ended December 31 **2018**	 2017
Power swaps and physical contracts in non-regulated operating revenues	**$ (12)**	$ 7
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**205**	401
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**–**	10
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**2**	2
	$ 195	$ 420

As at December 31, 2018, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2019	2020	2021	2022	2023
Natural gas purchases (Mmbtu)	308	108	71	50	41
Natural gas sales (Mmbtu)	247	42	9	2	–
Power purchases (MWh)	6	–	–	–	–
Power sales (MWh)	5	–	–	–	–

OTHER DERIVATIVES

For the millions of Canadian dollars	Year ended December 31 **2018** **Interest rate swaps**	2017 Interest rate swaps
Unrealized gain (loss) in interest expense, net	**$ (1)**	$ 2
Total gains (losses) in net income	**$ (1)**	$ 2

As at December 31, 2018, the Company had interest rate swaps in place for the $250 million non-revolving term credit facility in Brunswick Pipeline for interest payments through Q1 2019.

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, 2018, the maximum exposure the Company has to credit risk is $1,035 million (2017 – $1,148 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, 2018 was $346 million (2017 – $247 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, 2018, the Company had $118 million (2017 – $90 million) in financial assets, considered to be past due, which have been outstanding for an average 68 days. The fair value of these financial assets is $107 million (2017 – $78 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, 2018		December 31, 2017	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**$ 384**	**28%**	$ 326	23%
Commercial	**182**	**13%**	161	11%
Industrial	**57**	**4%**	46	3%
Other	**84**	**6%**	96	7%
	707	**51%**	629	44%
Trading group				
Credit rating of A- or above	**49**	**4%**	55	4%
Credit rating of BBB- to BBB+	**70**	**5%**	61	4%
Credit rating of CCC- to CCC+	**8**	**0%**	–	0%
Not rated	**108**	**8%**	96	7%
	235	**17%**	212	15%
Other accounts receivable	**273**	**20%**	300	22%
	1,215	**88%**	1,141	81%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**130**	**9%**	207	15%
Credit rating of BBB- to BBB+	**9**	**1%**	10	1%
Not rated	**28**	**2%**	36	3%
	167	**12%**	253	19%
	$ 1,382	**100%**	$ 1,394	100%

CASH COLLATERAL

The Company's cash collateral positions consisted of the following:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Cash collateral provided to others	**$ 103**	$ 119
Cash collateral received from others	**77**	99

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 falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2018, the total fair value of these derivatives, in a liability position, was $365 million (December 31, 2017 – $310 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.

13. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (refer to note 1) 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, 2018
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	$ –	$ 70	$ –	$ 70
Power purchases	2	–	–	2
Natural gas purchases and sales	–	2	–	2
Heavy fuel oil purchases	–	1	–	1
Foreign exchange forwards	–	29	–	29
	2	102	–	104
HFT derivatives				
Power swaps and physical contracts	2	2	3	7
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	36	18	55
	3	38	21	62
Other derivatives				
Interest rate swap	–	1	–	1
	–	1	–	1
Total assets	5	141	21	167
Liabilities				
Cash flow hedges				
Foreign exchange forwards	–	5	–	5
	–	5	–	5
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	–	1	–	1
Power purchases	1	–	–	1
Heavy fuel oil purchases	–	1	–	1
Natural gas purchases and sales	3	–	–	3
	4	2	–	6
HFT derivatives				
Power swaps and physical contracts	14	6	1	21
Natural gas swaps, futures, forwards and physical contracts	–	28	305	333
	14	34	306	354
Total liabilities	18	41	306	365
Net assets (liabilities)	$ (13)	$ 100	$ (285)	$ (198)

As at				December 31, 2017
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 5	$ –	$ –	$ 5
Foreign exchange forwards	–	2	–	2
	5	2	–	7
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	–	127	–	127
Power purchases	5	–	–	5
Natural gas purchases and sales	–	5	–	5
Heavy fuel oil purchases	4	8	–	12
Foreign exchange forwards	–	32	–	32
	9	172	–	181
HFT derivatives				
Power swaps and physical contracts	–	3	9	12
Natural gas swaps, futures, forwards, physical contracts and related transportation	–	26	25	51
	–	29	34	63
Other derivatives				
Interest rate swap	–	2	–	2
	–	2	–	2
Total assets	14	205	34	253
Liabilities				
Cash flow hedges				
Power swaps	2	–	–	2
Foreign exchange forwards	–	5	–	5
	2	5	–	7
Regulatory deferral				
Power purchases	3	–	–	3
Natural gas purchased and sales	5	1	–	6
Foreign exchange forwards	–	4	–	4
	8	5	–	13
HFT derivatives				
Power swaps and physical contracts	49	5	(4)	50
Natural gas swaps, futures, forwards and physical contracts	6	47	187	240
	55	52	183	290
Total liabilities	65	62	183	310
Net assets (liabilities)	$ (51)	$ 143	$ (149)	$ (57)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2018 was as follows:

		HFT Derivatives	
millions of Canadian dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2018	**$ 9**	**$ 25**	**$ 34**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(6)**	**(7)**	**(13)**
Balance, December 31, 2018	**$ 3**	**$ 18**	**$ 21**

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2018 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, January 1, 2018	$ (4)	$ 187	$ 183
Total realized and unrealized gains (losses) included in non-regulated operating revenues	5	118	123
Balance, December 31, 2018	$ 1	$ 305	$ 306

The Company evaluates the observable inputs of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the year ended December 31, 2018, there were no transfers between levels.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives include 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, 2018
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
HFT derivatives – Power swaps and physical contracts	$ 3	Modelled pricing	Third-party pricing	$24.31 – $50.29	$31.43
			Probability of default	0.03% – 0.13%	0.13%
			Discount rate	0.03% – 2.19%	1.45%
			Correlation factor	84.98% – 84.98%	84.98%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation	8	Modelled pricing	Third-party pricing	$1.80 – $12.21	$4.75
			Probability of default	0.01% – 2.94%	0.24%
			Discount rate	0.01% – 30.62%	4.25%
	10	Modelled pricing	Third-party pricing	$1.95 – $12.90	$8.68
			Basis adjustment	$0.07 – $3.43	$1.88
			Probability of default	0.01% – 3.20%	0.57%
			Discount rate	0.01% – 7.61%	0.42%
Total assets	$ 21				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	$20.80 – $50.29	$26.38
			Probability of default	0.08% – 0.29%	0.15%
			Discount rate	0.03% – 2.99%	1.65%
			Correlation factor	84.98% – 84.98%	84.98%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	286	Modelled pricing	Third-party pricing	$1.48 – $12.90	$5.75
			Own credit risk	0.01% – 2.94%	0.09%
			Discount rate	0.01% – 11.96%	2.35%
	19	Modelled pricing	Third-party pricing	$2.15 – $13.18	$7.54
			Basis adjustment	$0.07 – $3.43	$2.67
			Own credit risk	0.01% – 2.76%	0.10%
			Discount rate	0.01% – 7.61%	1.38%
Total liabilities	$ 306				
Net assets (liabilities)	$ (285)				

As at						December 31, 2017
millions of Canadian dollars		Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets						
HFT derivatives – Power swaps and physical contracts	$	1	Modelled pricing	Third-party pricing	$24.88 – $117.90	$92.93
				Probability of default	0.00% – 0.01%	0.00%
				Discount rate	0.00% – 0.13%	0.00%
		8	Modelled pricing	Third-party pricing	$63.48 – $117.00	$102.68
				Correlation factor	0.94% – 0.99%	0.96%
				Probability of default	0.00% – 0.00%	0.00%
				Discount rate	0.00% – 0.00%	0.00%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation		18	Modelled pricing	Third-party pricing	$2.06 – $8.24	$3.61
				Probability of default	0.00% – 0.05%	0.00%
				Discount rate	0.00% – 0.29%	0.06%
		7	Modelled pricing	Third-party pricing	$2.04 – $12.52	$6.42
				Basis adjustment	0.08% – 0.71%	0.52%
				Probability of default	0.00% – 0.00%	0.00%
				Discount rate	0.00% – 0.09%	0.01%
Total assets	$	34				
Liabilities						
HFT derivatives – Power swaps and physical contracts		(6)	Modelled pricing	Third-party pricing	$24.88 – $117.90	$95.46
				Own credit risk	0.00% – 0.01%	0.00%
				Discount rate	0.00% – 0.13%	0.00%
		2	Modelled pricing	Third-party pricing	$94.5 – $117.00	$105.52
				Correlation factor	0.94% – 0.99%	0.96%
				Probability of default	0.00% – 0.00%	0.00%
				Discount rate	0.00% – 0.00%	0.00%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		172	Modelled pricing	Third-party pricing	$1.89 – $11.81	$4.64
				Own credit risk	0.00% – 0.00%	0.00%
				Discount rate	0.00% – 0.12%	0.02%
		15	Modelled pricing	Third-party pricing	$2.15 – $12.52	$8.94
				Basis adjustment	0.08% – 0.71%	0.53%
				Own credit risk	0.00% – 0.00%	0.00%
				Discount rate	0.00% – 0.08%	0.01%
Total liabilities	$	183				
Net assets (liabilities)	$	(149)				

The financial assets and liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of the following:

As at millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2018	**$ 15,411**	**$ 15,908**	**$ –**	**$ 14,991**	**$ 917**	**$ 15,908**
December 31, 2017	$ 13,881	$ 15,217	$ 69	$ 14,346	$ 802	$ 15,217

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. An after-tax foreign currency loss of $122 million was recorded in Other Comprehensive Income for the year ended December 31, 2018 (2017 – $97 million gain after-tax). There was no ineffectiveness for the year ended December 31, 2018 (2017 – nil).

14. REGULATORY ASSETS AND LIABILITIES

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates or tolls collected from customers. Management believes 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.

REGULATORY ASSETS AND LIABILITIES

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Regulatory assets		
Deferred income tax regulatory assets	**$ 775**	$ 667
Pension and post-retirement medical plan (1)	**453**	380
Cost recovery clauses	**75**	17
Environmental remediations	**31**	41
Hurricane Matthew restoration	**28**	28
Stranded cost recovery	**28**	25
Unamortized defeasance costs	**26**	32
Demand side management ("DSM") deferral	**24**	28
Deferrals related to derivative instruments	**10**	15
Storm reserve	**4**	59
Other	**115**	119
	$ 1,569	$ 1,411
Current	**$ 165**	$ 138
Long-term	**1,404**	1,273
Total regulatory assets	**$ 1,569**	$ 1,411
Regulatory liabilities		
Deferred income tax regulatory liabilities	**1,218**	1,116
Accumulated reserve - cost of removal	**955**	894
Regulated fuel adjustment mechanism	**161**	177
Deferrals related to derivative instruments	**116**	182
Storm reserve	**76**	–
Cost recovery clauses	**30**	51
Self-insurance fund (note 31)	**30**	28
Other	**24**	20
	$ 2,610	$ 2,468
Current	**$ 251**	$ 226
Long-term	**2,359**	2,242
Total regulatory liabilities	**$ 2,610**	$ 2,468

(1) The December 31, 2017 pension and post-retirement medical plan regulatory asset includes a prior period reclassification of $35 million from AOCI, for changes in unrecognized pension and post-retirement benefit costs to be consistent with current year presentation. Refer to note 10 for further details.

Deferred Income Tax Regulatory Assets and Liabilities

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.

In 2017, as a result of enactment of the *US Tax Cuts and Jobs Act of 2017*, the Company revalued its United States deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company reduced its US regulated net deferred income tax liabilities by $1.1 billion and recorded an equivalent regulatory liability since the benefit of lower US taxes is expected to be returned to customers over time as required by the Act or by order of the applicable 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, and Emera Maine. It is included in rate base and earns a rate of return as permitted by the FPSC, New Mexico Public Regulation Commission ("NMPRC") and Maine Public Utilities Commission ("MPUC"), as applicable. It is amortized over the remaining service life of plan participants.

Cost Recovery Clauses

These assets and liabilities are related to Tampa Electric, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year.

Environmental Remediations

This asset is primarily related to PGS costs associated with the environmental remediation at Manufactured Gas Plant ("MGP") 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.

Hurricane Matthew Restoration

This asset represents restoration costs incurred by GBPC in 2016 associated with Hurricane Matthew. The asset is being amortized over five years and is included in rate base. The Grand Bahama Port Authority ("GBPA") has approved full recovery of these storm restoration costs.

Stranded Cost Recovery

Due to the decommissioning of a GBPC steam turbine during 2012, the GBPA approved the recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base for 2018 and 2017 and is expected to be included in future years.

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, 2018, totalled $759 million (2017 – $726 million). 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 permitted by the Nova Scotia Utility and Review Board ("UARB").

DSM Deferral

The UARB approved the implementation of the 2015 DSM deferral set at $35 million for 2015 and recoverable from customers over an eight year period beginning 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. In December 2016, EfficiencyOne secured 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 six years, it will repay the balance to EfficiencyOne. This 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.

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 as approved by the respective regulators. 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. 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.

Accumulated Reserve – Cost of Removal

This regulatory liability represents the non-ARO COR reserve in 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.

Regulated Fuel Adjustment Mechanism

This regulated liability is the difference between actual fuel costs and amounts recovered from NSPI customers through electricity rates in a given year, and are deferred to a fuel adjustment mechanism ("FAM") regulatory asset or liability and recovered from or returned to customers in a subsequent year. For the years 2017 to 2019, differences between actual fuel costs and fuel revenues recovered from customers will be recovered or returned to customers after 2019, as required under the *Electricity Plan Implementation (2015) Act*, ("*Electricity Plan Act*").

Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric and PGS systems. As allowed by the FPSC, if the charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. Tampa Electric and PGS 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 the reserve.

On September 10, 2017, Tampa Electric was impacted by Hurricane Irma and incurred total restoration costs of approximately $102 million USD. The amount charged to the storm reserve exceeded the balance in the reserve by $47 million USD, which was recorded as a regulatory asset on the balance sheet. This regulated asset was included in rate base. On December 28, 2017, Tampa Electric petitioned the FPSC for recovery of estimated restoration costs in excess of the storm reserve for several named storms and to replenish the reserve to the $56 million USD level that existed at October 31, 2013. On March 1, 2018, the FPSC approved a settlement agreement authorizing the utility to net the amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. At December 31, 2018, Tampa Electric's storm reserve liability was $56 million USD.

REGULATORY ENVIRONMENTS

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.

Tampa Electric

Tampa Electric's approved regulated return on equity ("ROE") range is 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.25 per cent is used for the calculation of the return on investments for clauses.

Tampa Electric has a fuel recovery clause approved by the FPSC, allowing it the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. 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 fuel costs and the cost-recovery rates and amounts recovered from customers through electricity rates in a year are deferred to a regulatory asset or liability and recovered from or returned to customers in a subsequent year.

In September 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new utility-scale solar photovoltaic projects across its service territory. On November 6, 2017, the FPSC approved a settlement agreement allowing a solar base rate adjustment ("SoBRA") that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects phased in from late 2018 through early 2021. On May 8, 2018, the FPSC approved Tampa Electric's first SoBRA. This SoBRA represents 145 MW and $24 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in September 2018. On October 29, 2018, the FPSC approved Tampa Electric's second SoBRA. This SoBRA represents 260 MW and $46 million USD annually in estimated revenue requirements and Tampa Electric began collecting these revenues in January 2019.

As discussed in the Storm Reserve section above, in September 2017, Tampa Electric was impacted by Hurricane Irma and incurred restoration costs in excess of the balance in its storm reserve. Tampa Electric petitioned the FPSC for recovery of estimated restoration costs in excess of the storm reserve for several named storms and to replenish the reserve. The FPSC approved a settlement agreement filed by Tampa Electric authorizing the utility to net the estimated amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. In Q1 2018, Tampa Electric recorded OM&G expense and a regulatory liability of $19 million USD to offset tax reform benefits. This deferral was amortized over the balance of the year as a credit against recognition of storm expense. In total, OM&G expense due to the allowed netting of the storm cost recovery with tax reform benefits, net of amortization of first quarter tax reform benefits, was approximately $103 million USD for the year ended December 31, 2018. Tampa Electric's final storm costs subject to netting will be determined in a separate regulatory proceeding in 2019. Any difference will be trued up and returned to customers in 2020. On August 20, 2018, the FPSC approved a reduction in base rates of $103 million USD annually beginning in 2019 as a result of lower tax expense.

PGS

The approved ROE range for PGS is 9.25 per cent to 11.75 per cent, based on an allowed equity capital structure of 54.7 per cent. Absent any rate case filing, the bottom of the range will increase to 9.75 per cent in 2021. An ROE of 10.75 per cent is used for the calculation of return on investments for clauses.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its purchased gas adjustment clause. This clause is designed to recover actual 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.

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 new 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 a 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 pipe.

On February 7, 2017, the FPSC approved a settlement agreement which resulted in new depreciation rates that reduce annual depreciation by $16 million USD and accelerate the amortization of the regulated asset related to the MGP environmental remediation costs. As part of the settlement, PGS and the Office of Public Counsel 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, with at least $21 million USD amortized over a two year recovery period beginning in 2016. In 2017 and 2016, PGS recorded $5 million USD and $16 million USD, respectively, of this amortization expense.

The 2017 PGS settlement agreement does not contain a provision for tax reform. On September 12, 2018, the FPSC approved a settlement agreement filed by PGS authorizing the utility to amortize $11 million USD of its MGP environmental regulatory asset and net it against its estimated 2018 tax reform benefits. Beginning in January 2019, PGS will lower base rates by $12 million USD to reflect the impact of tax reform and reduce depreciation rates by $10 million USD in accordance with the settlement agreement.

PGS is permitted to initiate a general base rate proceeding if it forecasts that ROE will fall below its allowed range.

NMGC

The approved ROE for NMGC is 10 per cent, on an allowed equity capital structure of 52 per cent. NMGC's rates were established in a 2012 rate case settlement and were frozen until December 31, 2017 per the June 2016 NMPRC order (the "Order") approving Emera's acquisition of TECO Energy. NMGC filed a rate case, including the prospective impact of tax reform, on February 26, 2018. A hearing in the rate case was held on September 24, 2018, where an uncontested stipulation on the rate request was presented. A second hearing on the rate case related to 2018 tax reform benefits was held on December 17, 2018. As of December 31, 2018, NMGC recorded a regulatory liability of $8 million USD to reflect 2018 tax reform benefits. A decision by the NMPRC on the rate case and on 2018 tax reform benefits is expected in 2019.

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 the 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.

NSPI

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* (the "Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval.

NSPI is 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 for 2018 and 2017 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.

The *Electricity Plan Implementation (2015) Act*, ("*Electricity Plan Act*"), was enacted by the Province of Nova Scotia in December 2015, 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. In July 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 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 in November 2016 and result in an average annual rate increase of 1.5 per cent for each of these three years.

In September 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link when it is in service. The Maritime Link entered service on January 15, 2018 and NSPI started paying the UARB approved interim assessment payments. As of December 31, 2018, $96 million has been paid to NSPML. The UARB approved annual payment for 2019 is $111 million. The payments are subject to a holdback of $10 million in each of 2018 and 2019 pending UARB agreement that a minimum of $10 million per year in benefits from the Maritime Link are realized for NSPI customers. If the $10 million in benefits is realized, the UARB will direct NSPI to pay the $10 million to NSPML for that year. If not realized, then the UARB will direct NSPI to pay to NSPML only that portion that is realized and the balance will be refunded to customers through NSPI's FAM. As of December 31, 2018, NSPI has recorded a $2 million holdback payable to NSPML.

In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment payment reflects a $53 million reduction in NSPML's assessment in each of 2018 and 2019, related to depreciation and amortization expenses. As these amounts are included in NSPI's 2017, 2018 and 2019 fuel rates and are being recovered from customers, NSPI is providing a credit to customers, including interest, as the payments from NSPI to NSPML are not required in those years. In 2018, $17 million was refunded. The credit to customers will be approximately $36 million in 2019 and $53 million in 2020.

After 2019 and the Rate Stability Plan, the timing and amounts payable to NSPML and NSPI's future rate recoveries of the Maritime Link costs will be subject to regulatory filings with the UARB, with expected filings in 2019 and 2020.

Emera Maine

Emera Maine's distribution operations and stranded cost recoveries are regulated by the MPUC. The transmission operations are regulated by the FERC. Rates for these are established in distinct regulatory proceedings. US tax reform benefits, resulting from the lower tax rate, were reflected in distribution and transmission rates effective July 1, 2018, with other components being deferred to be addressed in future 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. In June 2018, the MPUC approved a 5.3 per cent distribution rate increase. This increase was effective July 1, 2018 and is based on a 9.35 per cent ROE and a common equity component of 49 per cent. Prior to July 1, 2018, the allowed ROE was 9.0 per cent, on a common equity component of 49 per cent.

Transmission Operations

Emera Maine's transmission operations are split between two districts; Bangor Hydro District and Maine Public Service ("MPS"). Bangor Hydro District 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. The allowed ROE for Bangor Hydro District local transmission operations for 2018 and 2017 is 10.57 per cent. Bangor Hydro District's bulk transmission assets are managed by ISO-New England ("ISO-NE") as part of a region-wide pool of assets. The allowed ROE range for Bangor Hydro bulk transmission assets is 11.07 to 11.74 per cent for 2018 and 2017.

MPS District 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. The current allowed ROE for transmission operations is 9.6 per cent (2017 – 9.6 per cent).

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.

The Barbados Light & Power Company Limited

BLPC is regulated by the Fair Trading Commission, an independent regulator, under the Utilities Regulation (Procedural) Rules 2003. 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 was 10 per cent for 2018 and 2017.

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 approved calculation of the fuel charge is adjusted monthly.

In December 2018, the Government of Barbados signed the *Income Tax Amendment Act* into law. This legislation which is effective January 1, 2019, created a new corporate income tax rate schedule and eliminated certain tax credits. At the date of enactment, BLPC was required to remeasure its deferred income tax liability at the new lower corporate income tax rate, resulting in recognition of an income tax recovery of $9.6 million USD of which $6.9 million USD was deferred as a regulatory liability.

Grand Bahama Power Company Limited

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, 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 8.5 per cent for 2018 (2017 – 8.8 per cent). In December 2018, the GBPA approved GBPC's regulated return on rate base of 8.44 per cent for 2019.

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.

Dominica Electricity Services Ltd.

Domlec is regulated by the Independent Regulatory Commission, Dominica. On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base was 15 per cent for 2018 and 2017.

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.

Dominica experienced unprecedented damage as a result of Hurricane Maria in September 2017, reducing the customer base from approximately 36,000 to 26,000 at December 31, 2018. Many homes were destroyed and have not been rebuilt at this time. Domlec has fully restored power to all customers who request power and are able to receive it. Domlec maintains insurance for its generation fleet and, subsequent to Hurricane Maria, has obtained specialized insurance for its transmission and distribution networks.

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.

15. 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. Intercompany balances and intercompany 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. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are as follows:

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $97 million for the year ended December 31, 2018 (2017 – nil). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments.
- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $29 million for the year ended December 31, 2018 (2017 – $28 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2018 and at December 31, 2017.

16. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Customer accounts receivable – billed	**$ 844**	$ 805
Customer accounts receivable – unbilled	**296**	278
Allowance for doubtful accounts	**(11)**	(12)
Other receivables	**86**	70
Capitalized transportation capacity (1)	**179**	89
Income tax receivable	**175**	24
Prepaid expenses	**42**	59
Net investment in direct financing lease (note 20)	**9**	8
Due from related parties (note 15)	**–**	5
	$ 1,620	$ 1,326

(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.

17. HELD FOR SALE

On November 26, 2018, Emera announced an agreement to sell its three NEGG facilities for $590 million USD plus a final working capital adjustment made on close. Proceeds from the sale of the NEGG facilities will be used to reduce corporate level debt and support capital investment opportunities within the regulated utility business. The transaction is expected to close in the first quarter of 2019 and is subject to certain regulatory approvals including approval of the FERC. The applicable provisions of the *Hart-Scott-Rodino Antitrust Act* have been satisfied.

As at December 31, 2018, the assets of the NEGG facilities were classified as held for sale and were measured at the lower of their carrying value or fair value less costs to sell. The measurement did not result in a fair value adjustment and the assets are no longer being depreciated. Included in assets held for sale on the Consolidated Balance Sheets was $777 million ($570 million USD) related to Property, plant and equipment. The NEGG operations are included within the Company's Emera Energy segment.

18. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at millions of Canadian dollars	Estimated useful life	**December 31 2018**	December 31 2017
Generation (1)	3 to 131	**$ 11,092**	$ 11,010
Transmission	11 to 80	**3,047**	2,786
Distribution	4 to 80	**6,348**	5,660
Gas transmission and distribution	7 to 85	**3,398**	2,867
General plant and other	2 to 60	**2,158**	1,874
Total cost		**26,043**	24,197
Less: Accumulated depreciation (1)		**(8,567)**	(7,824)
		17,476	16,373
Construction work in progress		**1,236**	622
Net book value		**$ 18,712**	$ 16,995

(1) On November 26, 2018, the Company announced an agreement to sell the NEGG facilities and as of December 31, 2018, the Company has classified these assets as held for sale. As of December 31, 2017, these assets were recorded within Property, Plant and Equipment on the Consolidated Balance Sheets. Refer to note 17 for additional information.

19. 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.

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		**2018**		2017
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	**$ 2,683**	**$ 356**	$ 2,607	$ 358
Service cost	**51**	**6**	49	5
Plan participant contributions	**8**	**5**	8	4
Interest cost	**95**	**13**	99	14
Benefits paid	**(143)**	**(33)**	(129)	(27)
Actuarial (gains) losses	**(133)**	**(25)**	171	25
Settlements and curtailments	**(18)**	**-**	(35)	-
Foreign currency translation adjustment	**107**	**28**	(87)	(23)
Balance, December 31	**2,650**	**350**	2,683	356
Change in plan assets				
Balance, January 1	**2,408**	**45**	2,208	39
Employer contributions	**51**	**31**	109	27
Plan participant contributions	**8**	**5**	8	4
Benefits paid	**(143)**	**(33)**	(129)	(27)
Actual return on assets, net of expenses	**(105)**	**(3)**	313	5
Settlements and curtailments	**(18)**	**-**	(34)	-
Foreign currency translation adjustment	**99**	**4**	(67)	(3)
Balance, December 31	**2,300**	**49**	2,408	45
Funded status, end of year	**$ (350)**	**$ (301)**	$ (275)	$ (311)

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:

millions of Canadian dollars		**2018**		2017
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 2,623**	**$ 318**	$ 2,655	$ 325
Fair value of plan assets	**2,264**	**6**	2,370	6
Funded status	**$ (359)**	**$ (312)**	$ (285)	$ (319)

PLANS WITH ACCUMULATED BENEFIT OBLIGATION ("ABO") IN EXCESS OF PLAN ASSETS

The ABO for the defined benefit pension plans was $2,527 million as at December 31, 2018 (2017 – $2,561 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:

millions of Canadian dollars	**2018**	2017
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 2,504**	$ 1,608
Fair value of plan assets	**2,264**	1,409
Funded status	**$ (240)**	$ (199)

BALANCE SHEET

The amounts recognized in the Consolidated Balance Sheets consisted of the following:

As at millions of Canadian dollars		**December 31 2018**		December 31 2017
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (12)**	**$ (19)**	$ (23)	$ (18)
Long-term liabilities	**(347)**	**(294)**	(264)	(295)
Other long-term assets	**9**	**11**	10	–
Amount included in deferred income tax	**5**	**(2)**	2	–
AOCI, net of tax and regulatory assets	**628**	**60**	561	74
Net amount recognized	**$ 283**	**$ (244)**	$ 286	$ (239)

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. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans (1)			
Balance, January 1, 2018	$ 315	$ 251	$ (3)
Amortized in current period	(26)	(37)	1
Current year addition to AOCI or regulatory assets	73	32	–
Change in foreign exchange rate	27	–	–
Balance, December 31, 2018	$ 389	$ 246	$ (2)
Non-pension benefits plans (1)			
Balance, January 1, 2018	$ 78	$ (4)	$ –
Amortized in current period	2	1	–
Current year addition to AOCI or regulatory assets	(17)	(4)	–
Change in foreign exchange rate	2	–	–
Balance, December 31, 2018	$ 65	$ (7)	$ –

(1) The January 1, 2018 balances include a prior period reclassification from AOCI to Regulatory assets, for changes in unrecognized pension and post-retirement benefit costs to be consistent with current year presentation. Refer to notes 10 and 14 for further details.

	2018		2017	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses	**$ 246**	**$ (7)**	$ 251	$ (4)
Past service (gains) costs	**(2)**	**–**	(3)	–
Regulatory assets	**389**	**65**	315	78
Total AOCI and regulatory assets before deferred income taxes	**633**	**58**	563	74
Amount included in deferred income tax assets	**(5)**	**2**	(2)	–
Net amount in AOCI and regulatory assets	**$ 628**	**$ 60**	$ 561	$ 74

BENEFIT COST COMPONENTS

Emera's net periodic benefit cost included the following:

As at				Year ended December 31
millions of Canadian dollars	2018		2017	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 51**	**$ 6**	$ 49	$ 5
Interest cost	**95**	**13**	99	14
Expected return on plan assets	**(138)**	**(2)**	(129)	(3)
Current year amortization of:				
Actuarial losses	**33**	**(1)**	38	2
Past service costs (gains)	**(1)**	**–**	–	(8)
Regulatory assets (liability)	**26**	**(2)**	17	(1)
Settlement, curtailments	**4**	**–**	(1)	–
Total	**$ 70**	**$ 14**	$ 73	$ 9

The expected return on plan assets is determined based on the market-related value of plan assets of $2,223 million as at January 1, 2018 (2017 – $2,153 million), adjusted for interest on certain cash flows during the year. 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% to 5%
Fixed income	35% to 50%
Equities:	
Canadian	12% to 22%
Non-Canadian	30% to 55%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average
Fixed income	48% to 53%
Equities	47% to 52%

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:

millions of Canadian dollars					**December 31, 2018**
	NAV	**Level 1**	**Level 2**	**Total**	**Percentage**
Cash and cash equivalents	**$ –**	**$ 30**	**$ –**	**$ 30**	**1%**
Net in-transits	**–**	**(56)**	**–**	**(56)**	**–2%**
Equity Securities:					
Canadian equity	**–**	**191**	**–**	**191**	**8%**
US equity	**–**	**330**	**–**	**330**	**14%**
Other equity	**–**	**157**	**–**	**157**	**7%**
Fixed income securities:					
Government	**–**	**–**	**119**	**119**	**5%**
Corporate	**–**	**–**	**108**	**108**	**5%**
Other	**–**	**4**	**3**	**7**	**–**
Mutual funds	**–**	**132**	**–**	**132**	**6%**
Other	**–**	**8**	**4**	**12**	**1%**
Open-ended investments measured at NAV (1)	**820**	**–**	**–**	**820**	**36%**
Common collective trusts measured at NAV (2)	**450**	**–**	**–**	**450**	**19%**
Total	**$ 1,270**	**$ 796**	**$ 234**	**$ 2,300**	**100%**

millions of Canadian dollars					December 31, 2017
	NAV	Level 1	Level 2	Total	Percentage
Cash and cash equivalents	$ –	$ 32	$ –	$ 32	1%
Net in-transits	–	(36)	–	(36)	–1%
Equity Securities:					
Canadian equity	–	214	–	214	9%
US equity	–	390	–	390	16%
Other equity	–	197	–	197	8%
Fixed income securities:					
Government	–	–	72	72	3%
Corporate	–	–	56	56	2%
Other	–	5	–	5	–
Mutual funds	–	246	–	246	10%
Other	–	–	4	4	–
Open-ended investments measured at NAV (1)	819	–	–	819	34%
Common collective trusts measured at NAV (2)	409	–	–	409	18%
Total	$ 1,228	$ 1,048	$ 132	$ 2,408	100%

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated daily and the funds honor 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 seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

Refer to note 13 for more information on the fair value hierarchy and inputs used to measure fair value.

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.

INVESTMENTS IN EMERA

As at December 31, 2018 and 2017, 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		
2019	$ 53	$ 22
Expected benefit payments		
2019	149	24
2020	152	25
2021	162	25
2022	169	25
2023	175	26
2024 - 2028	988	127

ASSUMPTIONS

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2018		2017	
(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	**4.05%**	**4.30%**	3.55%	3.65%
Rate of compensation increase	**3.30%**	**3.67%**	3.12%	3.28%
Health care trend - initial (next year)	**-**	**6.39%**	-	6.65%
- ultimate	**-**	**4.45%**	-	4.45%
- year ultimate reached	**-**	**2035**	-	2036
Benefit cost for year ended December 31:				
Discount rate	**3.55%**	**3.65%**	3.96%	4.18%
Expected long-term return on plan assets	**6.38%**	**3.73%**	6.29%	6.08%
Rate of compensation increase	**3.12%**	**3.28%**	2.82%	2.54%
Health care trend - initial (current year)	**-**	**6.65%**	-	6.78%
- ultimate	**-**	**4.45%**	-	4.45%
- year ultimate reached	**-**	**2036**	-	2035

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 2018:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	$ 1	$ (1)
Accumulated post-retirement benefit obligation, December 31	17	(15)

SENSITIVITY ANALYSIS FOR DEFINED BENEFIT PENSION PLANS

The impact on the 2018 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	$ (9)	$ 9
Asset rate assumption	(6)	6

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 2019:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Actuarial gains (losses)	$ (15)	$ (1)
Past service gains	1	6
Regulatory assets	(16)	2
Total	$ (30)	$ 7

DEFINED CONTRIBUTION PLAN

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2018 was $31 million (2017 – $23 million).

20. NET INVESTMENT IN DIRECT FINANCING LEASE

Emera's net investment in direct financing lease primarily relates to Brunswick Pipeline. 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 millions of Canadian dollars	**December 31 2018**	December 31 2017
Total minimum lease payments to be received	**$ 1,066**	$ 1,126
Less: amounts representing estimated executory costs	**(201)**	(211)
Minimum lease payments receivable	**$ 865**	$ 915
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: unearned finance lease income	**(564)**	(609)
Net investment in direct financing lease	**$ 484**	$ 489
Principal due within one year (included in Receivables and other current assets)	**9**	8
Net investment in direct financing lease – long-term	**$ 475**	$ 481

Future minimum lease payments to be received for the next five years:

For the	Year ended December 31				
millions of Canadian dollars	2019	2020	2021	2022	2023
Minimum lease payments to be received	$ 65	$ 65	$ 65	$ 65	$ 64
Less: amounts representing estimated executory costs	(12)	(12)	(12)	(12)	(12)
Minimum lease payments receivable	$ 53	$ 53	$ 53	$ 53	$ 52

21. GOODWILL

The change in goodwill for the year ended December 31 is due to the following:

millions of Canadian dollars	**2018**	2017
Balance, January 1	**$ 5,805**	$ 6,213
Change in foreign exchange rate	**508**	(408)
Balance, December 31	**$ 6,313**	$ 5,805

Goodwill on Emera's Consolidated Balance Sheets relates to the acquisitions of TECO Energy, Emera Maine and GBPC. Goodwill is subject to an annual assessment for impairment at the reporting unit level. Emera's reporting units with goodwill are Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC.

A qualitative impairment assessment was performed for Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC, concluding that the fair value of the reporting units exceeded their respective carrying values, and as such, no quantitative assessments were performed and no impairment charges were recognized.

22. 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	**2018**	**Weighted average interest rate**	2017	Weighted average interest rate
TECO Finance				
Advances on revolving credit and term facilities	**$ 805**	**3.43%**	$ 820	2.58%
Tampa Electric Company				
Advances on accounts receivable and revolving credit facilities	**302**	**3.10%**	382	2.07%
NMGC				
Advances on revolving credit facilities	**79**	**3.40%**	38	2.47%
NSPI				
Bank indebtedness	**–**	**–%**	1	–%
Short-Term debt	**$ 1,186**		$ 1,241	

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		2018		2017
TECO Energy/TECO Finance – term credit facility	2019	$	**682**	$	502
TECO Energy/TECO Finance – revolving credit facility	2022		**546**		376
Tampa Electric Company – revolving credit facility	2022		**443**		408
Tampa Electric Company – accounts receivable revolving credit facility	2021		**205**		188
Tampa Electric Company – term loan	2018		**–**		377
NMGC – revolving credit facility	2022		**171**		157
GBPC – revolving credit facility	2019		**18**		16
Total			**2,065**		2,024
Less:					
Advances under revolving credit and term facilities			**1,186**		1,241
Letters of credit issued within the credit facilities			**3**		3
Total advances under available facilities			**1,189**		1,244
Available capacity under existing agreements		$	**876**	$	780

The weighted average interest rate on outstanding short-term debt at December 31, 2018 was 3.34 per cent (2017 – 2.42 per cent).

RECENT FINANCING ACTIVITY

Emera Florida and New Mexico

On October 11, 2018, TEC repaid a $300 million USD 1-year term credit facility using proceeds from a senior note issuance. Refer to note 24.

On March 23, 2018, TEC extended the maturity date of its $150 million USD accounts receivable collateralized borrowing facility from March 23, 2018 to March 22, 2021. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $300 million USD revolving credit facility by $100 million USD to $400 million USD. There were no other changes in commercial terms.

On March 7, 2018, TECO Energy/Finance increased its $400 million USD term bank credit facility by $100 million USD to $500 million USD, and extended the maturity date to March 8, 2019. There were no other changes in commercial terms.

23. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars		December 31 2018		December 31 2017
Accrued charges	$	**154**	$	134
Accrued interest on long-term debt		**93**		78
Pension and post-retirement liabilities (note 19)		**31**		41
Sales and other taxes payable		**9**		11
Emission credits obligations (1)		**8**		21
Income tax payable		**6**		1
Other		**127**		64
	$	**428**	$	350

(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 11) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

24. LONG-TERM DEBT

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, 2018, consisted of the following:

	Weighted average interest rate (1)				
millions of Canadian dollars	2018	2017	Maturity	**2018**	2017
Emera					
Bankers acceptances, LIBOR loans	Variable	Variable	2020	**$ 339**	$ 133
Unsecured fixed rate notes	3.50%	3.50%	2019–2023	**725**	725
Fixed to floating subordinated notes (USD)	6.75%	6.75%	2076	**1,637**	1,505
				$ 2,701	$ 2,363
Emera US Finance LP					
Unsecured senior notes (USD)	3.60%	3.60%	2019–2046	**$ 4,434**	$ 4,077
TECO Finance (2)					
Variable rate notes (USD)		Variable	2018	**$ -**	$ 314
Fixed rate notes and bonds (USD)	5.15%	5.15%	2020	**409**	376
				$ 409	$ 690
Tampa Electric (3)					
Fixed rate notes and bonds (USD)	4.64%	4.75%	2021–2049	**$ 3,126**	$ 2,410
PGS					
Fixed rate notes and bonds (USD)	4.66%	5.06%	2021–2049	**$ 425**	$ 328
NMGC					
Fixed rate notes and bonds (USD)	4.53%	4.53%	2021–2026	**$ 368**	$ 339
NMGI					
Fixed rate notes and bonds (USD)	3.41%	3.41%	2019–2024	**$ 273**	$ 251
NSPI					
Discount notes	Variable	Variable	2023	**$ 516**	$ 364
Medium term fixed rate notes	5.73%	5.73%	2025–2097	**1,965**	1,965
Fixed rate debenture	9.75%	9.75%	2019	**95**	95
				$ 2,576	$ 2,424
Emera Maine					
LIBOR loans and demand loans	Variable	Variable	2023	**$ 28**	$ 51
Secured fixed rate mortgage bonds (USD)	9.74%	9.74%	2020–2022	**68**	63
Unsecured senior fixed rate notes (USD)	4.23%	4.15%	2022–2048	**382**	294
				$ 478	$ 408
EBP					
Senior secured credit facility	3.08%	3.08%	2022	**$ 248**	$ 248
GBPC					
Amortizing fixed rate notes (USD)	3.83%	3.77%	2021–2022	**$ 114**	$ 78
Senior notes (USD)	7.07%	7.07%	2020–2023	**68**	88
				$ 182	$ 166

(continued)

millions of Canadian dollars	Weighted average interest rate (1) 2018	Weighted average interest rate (1) 2017	Maturity	2018	2017
ICDU					
Fixed rate note (USD)	4.00%	–	2023	**$ 24**	$ –
BLPC & ECI					
Secured senior notes (USD)	Variable	Variable	2021	**159**	168
Secured fixed rate senior notes (4)	4.74%	5.06%	2020–2035	**$ 99**	$ 76
				$ 258	$ 244
Adjustments					
Fair market value adjustment – TECO Energy acquisition (5)				**$ 22**	$ 31
Debt issuance costs				**(113)**	(98)
Amount due within one year				**(1,119)**	(741)
				$ (1,210)	$ (808)
Long-Term Debt				**$ 14,292**	$ 13,140

(1) Weighted average interest rate of fixed rate long-term debt.
(2) TECO Energy is a full and unconditional guarantor of TECO Finance's securities, and no subsidiaries of TECO Energy guarantee TECO Finance's securities.
(3) 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.
(4) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).
(5) 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	2018	2017
Emera – revolving credit facility (1)	June 2020	**$ 900**	$ 900
NSPI – revolving credit facility (1)	October 2023	**600**	600
Emera Maine – revolving credit facility	February 2023	**109**	100
BLPC – revolving credit facility	2021 – 2022	**26**	24
Total		**1,635**	1,624
Less:			
Borrowings under credit facilities		**899**	598
Letters of credit issued inside credit facilities		**77**	44
Use of available facilities		**976**	642
Available capacity under existing agreements		**$ 659**	$ 982

(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, 2018
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.60 : 1

RECENT FINANCING ACTIVITY

Emera

On May 16, 2018, Emera filed a $750 million debt and preferred equity shelf prospectus, providing the Company with access to raise long-term debt and preferred equity. On May 31, 2018, preferred shares were issued under this base shelf prospectus for gross proceeds of $300 million (refer to note 27). As at December 31, 2018 the Company has $450 million available for issuance under this prospectus, which expires on June 16, 2020.

Emera Florida and New Mexico

On October 4, 2018, TEC completed a $375 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.45 per cent and have a maturity date of June 15, 2049. Proceeds from this issuance were used to repay a $300 million USD 1-year term credit facility. Refer to note 22.

On June 7, 2018, TEC completed a $350 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.30 per cent and maturity date of June 15, 2048.

On April 10, 2018, TECO Energy/Finance repaid a $250 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

NSPI

On October 31, 2018, NSPI amended its operating credit facility to extend the maturity from October 2021 to October 2023. There were no other changes in commercial terms.

Emera Maine

On November 15, 2018, Emera Maine completed a $50 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.71 per cent and will mature on November 15, 2048. Proceeds from this issuance were used for general corporate purposes.

On February 28, 2018, Emera Maine extended the maturity date of its $80 million USD operating credit facility from September 25, 2019 to February 28, 2023. There were no other changes in commercial terms.

ECI

On January 12, 2018, a wholly owned indirect subsidiary of ECI entered into a five year $18 million Bahamian dollar loan agreement with an interest rate of 4.00 per cent and maturity date of January 12, 2023.

EBP

On October 31, 2018, Emera Brunswick Pipeline amended its Credit Agreement to extend the maturity from February 2021 to February 2022. There were no other changes in commercial terms.

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	2019	2020	2021	2022	2023	Thereafter	Total
Emera	$ 225	$ 339	$ –	$ –	$ 500	$ 1,637	$ 2,701
Emera US Finance LP	682	–	1,023	–	–	2,729	4,434
TECO Finance	–	409	–	–	–	–	409
Tampa Electric	–	–	315	307	–	2,504	3,126
PGS	–	–	64	34	–	327	425
NMGC	–	–	273	–	–	95	368
NMGI	69	–	–	–	–	204	273
NSPI	95	–	–	–	516	1,965	2,576
Emera Maine	–	41	–	123	28	286	478
EBP	–	–	–	248	–	–	248
GBPC	17	50	37	33	45	–	182
ICDU	–	–	–	–	24	–	24
BLPC & ECI	31	59	30	13	25	100	258
Total	$ 1,119	$ 898	$ 1,742	$ 758	$ 1,138	$ 9,847	$ 15,502

25. 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 AROs 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	**2018**	2017
Balance, January 1	**$ 172**	$ 170
Additions (1)	**25**	2
Liabilities settled	**(2)**	(3)
Accretion included in depreciation expense	**6**	6
Other	**(1)**	1
Change in foreign exchange rate	**5**	(4)
Balance, December 31	**$ 205**	$ 172

(1) Tampa Electric produces ash and other by-products, collectively known as CCRs, at its Big Bend and Polk power stations. The 2018 additions to ARO are to achieve compliance with the EPA's CCR rule, which contains design and operating standards for CCR management units. Tampa Electric submitted a petition to the FPSC in December 2018 for recovery of costs associated with the ongoing project and the petition is currently under review.

26. COMMITMENTS AND CONTINGENCIES

A. COMMITMENTS

As at December 31, 2018, 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	2019	2020	2021	2022	2023	Thereafter	Total
Purchased power (1)	$ 204	$ 203	$ 209	$ 208	$ 209	$ 2,194	$ 3,227
Transportation (2) (3)	569	347	255	215	170	1,492	3,048
Fuel and gas supply	642	237	49	7	3	–	938
Capital projects (4)	524	147	45	11	3	8	738
Long-term service agreements (5) (6)	110	67	42	30	33	246	528
Equity investment commitments (7)	–	190	–	–	–	–	190
Leases and other (8)	18	15	10	9	7	75	134
Demand side management	44	1	–	–	–	–	45
	$ 2,111	$ 1,207	$ 610	$ 480	$ 425	$ 4,015	$ 8,848

(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) Includes $82 million related to NEGG transportation capacity ($5 million in 2019; $5 million in 2020; $5 million in 2021; $4 million in 2022; $4 million in 2023 and $59 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to note 17 for additional information.
(4) Includes $439 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.
(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) Includes $248 million related to various long-term service agreements NEGG has entered into for maintenance of certain generating equipment ($46 million in 2019; $9 million in 2020; $24 million in 2021; $16 million in 2022; $16 million in 2023 and $137 million thereafter). On completion of the sale of the NEGG facilities, the remaining future contractual obligations will be transferred to the buyer. Refer to note 17 for additional information.
(7) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(8) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. In January 2018, NSPI started paying the UARB approved interim assessment payments and as of December 31, 2018, $96 million has been paid to NSPML. The UARB approved payment for 2019 is $111 million and is subject to a $10 million holdback. Refer to note 14 for additional information. After 2019, the timing of and amounts payable to NSPML will be subject to regulatory filings with the UARB, with expected filings in 2019 and 2020.

B. LEGAL PROCEEDINGS

Emera Florida and New Mexico

TECO Guatemala Holdings ("TGH")

In 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 Free 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 two per cent. This award was upheld in subsequent annulment proceedings in 2016 and, in addition, TGH's application for partial annulment of the award was granted, and Guatemala was ordered 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. A new tribunal was constituted and the matter has been fully briefed. A hearing is scheduled for March 2019 and a decision is expected from the tribunal in 2020. In addition, TGH has sued Guatemala in Washington, D.C. court to enforce the $21 million USD owing. Guatemala's motion to dismiss the enforcement action was denied. The parties are in the process of filing motions on the matter. Results to date do not reflect any benefit.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at December 31, 2018, TEC has estimated its financial liability to be $38 million ($28 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. 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 believed to be currently credit-worthy and are likely to continue to be credit-worthy 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. Other factors that could impact these estimates include 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 base rate proceedings.

Emera Maine

From 2011 to 2016, four separate complaints were filed with the FERC to challenge the base ROE under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT").

- Complaint I, filed by a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users, was remanded to the FERC by the US Court of Appeals in 2017 for further proceedings. No reserve has been made with respect to Complaint I due to uncertainty of the outcome.
- Complaints II and III (the "ENE" and "MA AG II" cases), brought by a group of consumer advocates and by a group of state commissions, state public advocates and end users respectively, have been joined together and are presently pending before the FERC. Emera Maine has recorded a reserve of approximately $4 million USD for these cases. These reserves 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 based on Emera Maine's best estimate of the probable outcome.
- Complaint IV was filed by the Eastern Massachusetts Consumer Owned Systems ("EMCOS"). On March 27, 2018, a FERC Administrative Law Judge issued an Initial Decision concluding that the currently-filed base ROE of 10.57 per cent, which with incentive adders may reach a maximum ROE of 11.74 per cent, is not unjust and unreasonable. This decision was appealed to the FERC. No reserve has been made in relation to Complaint IV due to the uncertainty of the final outcome.

On October 16, 2018, the FERC issued an order that addressed all four complaint proceedings. The FERC order proposed a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding was a 10.41 per cent base ROE for the ISO-NE OATT. The FERC has permitted parties to comment on the new methodology and its application to the four pending complaint proceedings. No new or additional reserves have been made with respect to all four pending complaints due to uncertainty.

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. PRINCIPAL FINANCIAL RISKS AND UNCERTAINTIES

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 12 and note 13.

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.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, 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 foreign currency derivative instruments to hedge specific transactions. The Company may enter into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams and capital expenditures. 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 do not impact net income as they are reported in AOCI.

Liquidity and Capital Market Risk

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, select asset sales, short-term credit facilities, and ongoing access to capital markets. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to a number of risk factors including financial market conditions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment. Emera is subject to risk with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access to cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

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 decrease in a credit rating could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations. Emera manages this risk by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation, preferred share units and deferred share units.

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. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's 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.

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 assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. 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.

D. GUARANTEES AND LETTERS OF CREDIT

Emera has several significant guarantees and letters of credit on behalf of third parties outstanding. The following guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2018:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which is expected to terminate on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

The Company has standby letters of credit and surety bonds in the amount of $67 million USD to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in February 2019 and is renewed annually. The amount committed as of December 31, 2018 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The letter of credit expires in June 2019 and is renewed annually. The amount committed as at December 31, 2018 was $49 million.

Collaborative Arrangements

For the years ended December 31, 2018 and 2017, 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 OM&G expenses. In 2018, NSPI recognized $19 million net expense (2017 – $18 million) in "Regulated fuel for generation and purchased power" and $2 million (2017 – $3 million) in OM&G.

27. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

	Annual Dividend Per Share	Redemption Price per share	**December 31, 2018** Issued and Outstanding	**December 31, 2018** Net Proceeds	December 31, 2017 Issued and Outstanding	December 31, 2017 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	$ 1.1802	$ 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
Series H	$ 1.2250	$ 25.00	**12,000,000**	**$ 295**	–	$ –
Total			**41,000,000**	**$ 1,004**	29,000,000	$ 709

Characteristics of the First Preferred Shares:

First Preferred Shares (1) (2)	Initial Yield (%)	Current Annual Dividend ($)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a one for one basis
Fixed rate reset (3) (4)						
Series A	4.400	0.6388	1.84	August 15, 2020	25.00	Series B
Series C (5)	4.100	1.1802	2.65	August 15, 2023	25.00	Series D
Series F	4.250	1.0625	2.63	February 15, 2020	25.00	Series G
Minimum rate reset (3) (4)						
Series B	2.393	Floating	1.84	August 15, 2020	25.00	Series A
Series H	4.900	1.2250	4.90	August 15, 2023	25.00	Series I
Perpetual fixed rate						
Series E (6)	4.500	1.1250			26.00	

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.

(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preferred Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

(3) On the redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent) and for Series B equals the Government of Treasury Bill Rate on the applicable reset date, plus 1.84 per cent.

(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series D, Series G and Series I shares without the consent of the holder 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, 2018, February 15, 2020 and August 15, 2023, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.

(5) The annual fixed dividend per share for First Preferred Shares, Series C was reset from $1.0250 to $1.1802 for the five-year period from and including August 15, 2018.

(6) First Preferred Shares, Series E are redeemable at $26.00 to August 15, 2019, decreasing $0.25 each year until August 15, 2022 and $25.00 per share thereafter.

First Preferred Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends is deducted on the Consolidated Statements of Income before arriving at "Net earnings attributable to common shareholders" and is 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, for only so long as the dividends remain in arrears, 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.

28. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars	**December 31 2018**	December 31 2017
Domlec	**$ 22**	$ 21
Preferred shares of GBPC	**19**	19
ICDU [(1)]	**-**	52
	$ 41	$ 92

(1) On January 15, 2018, Emera completed the acquisition of the minority shareholder common shares for total consideration of $35 million USD. This acquisition increases Emera's indirect ownership interest to 100 per cent.

PREFERRED SHARES OF GBPC:

Authorized:

20,000 non-voting cumulative redeemable variable perpetual preferred shares.

	2018		2017	
Issued and outstanding:	**number of shares**	**millions of dollars**	number of shares	millions of dollars
Outstanding as at December 31	**20,000**	**$ 19**	20,000	$ 19

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.

29. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the	Year ended December 31	
millions of Canadian dollars	**2018**	2017
Changes in non-cash working capital:		
Inventory	**$ (44)**	$ 31
Receivables and other current assets	**(144)**	(154)
Accounts payable	**59**	3
Other current liabilities	**13**	16
Total non-cash working capital	**$ (116)**	$ (104)
Supplemental disclosure of cash paid:		
Interest	**$ 653**	$ 689
Income taxes	**$ 33**	$ 63
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 181**	$ 166
Change in accrued capital expenditures	**$ (50)**	$ 13
Issuance of depository receipts	**$ 22**	$ –

30. 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 that employee's 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. As at December 31, 2018, Emera is in compliance with this requirement.

Compensation cost for shares issued by Emera for the year ended December 31, 2018 under the Employee Common Share Purchase Plan was $1 million (2017 – $1 million) and is included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan") or ("DRIP"), which provides an opportunity for shareholders to reinvest dividends 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.

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 ten 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. As at December 31, 2018, Emera is in compliance with this requirement.

Stock options vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. If an option is not exercised within ten 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.

Unless a stock option has expired, vested options may be exercised within the 24 months following the option holders date of retirement or termination for other than just cause, and within six months following the date of termination for just cause, resignation or death. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

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:

	2018	2017
Weighted average fair value per option	**$ 1.70**	$ 2.37
Expected term (1)	**6 years**	5 years
Risk-free interest rate (2)	**2.13%**	1.22%
Expected dividend yield (3)	**5.69%**	4.60%
Expected volatility (4)	**13.71%**	14.41%

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.
(2) Based on the Bank of Canada five-year government bond yields.
(3) Incorporates current dividend rates and historical dividend increase patterns.
(4) Estimated using the five-year historical volatility.

The following table summarizes stock option information for 2018:

	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, 2017	3,643,575	$ 39.42	1,739,650	$ 2.52
Granted	627,600	39.93	627,600	1.70
Exercised	(23,800)	24.98	N/A	N/A
Vested	N/A	N/A	(666,125)	2.51
Forfeited	(11,700)	45.10	(11,700)	2.54
Expired	(10,100)	39.93	(10,100)	1.70
Options outstanding December 31, 2018	**4,225,575**	**$ 39.56**	**1,679,325**	**$ 2.22**
Options exercisable December 31, 2018 (2) (3)	**2,546,250**	**$ 37.15**		

(1) As at December 31, 2018, there was $5 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 2.2 years (2017 – $3 million, 2.5 years).
(2) As at December 31, 2018, the weighted average remaining term of vested options was 5.1 years with an aggregate intrinsic value of $18 million (2017 – 5.4 years, $22 million).
(3) As at December 31, 2018, the fair value of options that vested in the year was $2 million (2017 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2018 was $1 million (2017 – $2 million), which is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

As at December 31, 2018, cash received from option exercises was $1 million (2017 – $3 million). The total intrinsic value of options exercised for the year ended December 31, 2018 was $1 million (2017 – $2 million). The range of exercise prices for the options outstanding as at December 31, 2018 was $21.99 to $46.19 (2017 – $21.58 to $46.19).

SHARE UNIT PLANS

The Company has DSU and PSU plans and the 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, the Director's DSU account is credited with additional DSUs, also referred to as DRIP. 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 per cent of the value of their actual annual incentive award (25 per cent 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, 2018 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, 2017	751,600	$ 28.44	472,485	$ 35.33
Granted including DRIP	90,549	38.72	101,676	43.93
Exercised	(5,040)	30.15	(10,640)	25.31
Outstanding and exercisable as at December 31, 2018	**837,109**	**$ 29.54**	**563,521**	**$ 37.07**

Compensation cost recognized for employee and director DSU for the year ended December 31, 2018 was $2 million (2017 – $7 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2018 were $1 million (2017 – $2 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2018 was $37 million (2017 – $35 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, resulting in a cash payment. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Dividend equivalents are awarded and paid in the form of 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 termination, disability or death.

A summary of the activity related to employee PSUs for the year ended December 31, 2018 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2017	829,998	$ 43.41	$ 41.1
Granted including DRIP	486,181	47.84	
Exercised	(176,805)	38.85	
Forfeited	(12,260)	44.88	
Outstanding as at December 31, 2018	**1,127,114**	**$ 46.02**	**$ 56.9**

Compensation cost recognized for the PSU plan for the year ended December 31, 2018 was $14 million (2017 – $14 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2018 were $4 million (2017 – $4 million).

31. VARIABLE INTEREST ENTITIES

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 primary 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. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a SIF, 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 "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

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, 2018**		December 31, 2017	
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)	**$ 545**	**$ 51**	$ 510	$ 67

32. 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.

33. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 15, 2019, the date the financial statements were issued.

34. 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 Emera US Holdings Inc. (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 condensed 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.

Emera Incorporated

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
For the year ended December 31, 2018						
Operating revenues	$ –	$ –	$ 4,432	$ 2,146	$ (54)	**$ 6,524**
Operating expenses	45	–	3,468	1,665	(52)	**5,126**
Income (loss) from equity investments and subsidiaries	801	–	3	150	(800)	**154**
Other income (expenses), net	22	–	20	(27)	(38)	**(23)**
Interest expense, net (1)	79	(40)	456	218	–	**713**
Income (loss) before provision for income taxes	699	40	531	386	(840)	**816**
Income tax expense (recovery)	(47)	9	64	43	–	**69**
Net income (loss)	746	31	467	343	(840)	**747**
Non-controlling interest in subsidiaries	–	–	–	(1)	2	**1**
Preferred stock dividends	36	–	38	4	(42)	**36**
Net income (loss) attributable to common shareholders	$ 710	$ 31	$ 429	$ 340	$ (800)	**$ 710**
Comprehensive income (loss) of Emera Incorporated	$ 1,249	$ 56	$ 973	$ 439	$ (1,468)	**$ 1,249**
For the year ended December 31, 2017						
Operating revenues	$ –	$ –	$ 4,274	$ 2,009	$ (57)	$ 6,226
Operating expenses	41	–	3,241	1,583	(57)	4,808
Income (loss) from equity investments and subsidiaries	337	–	1	122	(336)	124
Other income (expenses), net	38	–	15	(46)	(32)	(25)
Interest expense, net (1)	84	(40)	451	203	–	698
Income (loss) before provision for income taxes	250	40	598	299	(368)	819
Income tax expense (recovery)	(44)	17	511	36	–	520
Net income (loss)	294	23	87	263	(368)	299
Non-controlling interest in subsidiaries	–	–	–	1	4	5
Preferred stock dividends	28	–	29	13	(42)	28
Net income (loss) attributable to common shareholders	$ 266	$ 23	$ 58	$ 249	$ (330)	$ 266
Comprehensive income (loss) of Emera Incorporated	$ (6)	$ 3	$ (291)	$ 265	$ 23	$ (6)

(1) Interest expense is net of interest revenue.

Emera Incorporated

CONDENSED CONSOLIDATED BALANCE SHEETS

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
As at December 31, 2018						
Assets						
Current assets	$ 146	$ 67	$ 1,767	$ 1,096	$ (244)	**$ 2,832**
Property, plant and equipment	24	–	13,745	4,946	(3)	**18,712**
Other assets						
Regulatory assets	–	–	645	759	–	**1,404**
Goodwill	–	–	6,208	105	–	**6,313**
Other long-term assets	11,457	4,660	971	3,200	(17,235)	**3,053**
Total other assets	11,457	4,660	7,824	4,064	(17,235)	**10,770**
Total assets	$ 11,627	$ 4,727	$ 23,336	$ 10,106	$ (17,482)	**$ 32,314**
Liabilities and Equity						
Current liabilities	$ 368	$ 695	$ 2,829	$ 926	$ (265)	**$ 4,553**
Long-term liabilities						
Long-term debt	2,906	3,709	10,243	4,428	(6,994)	**14,292**
Deferred income taxes	–	3	668	643	6	**1,320**
Regulatory liabilities	–	–	2,118	241	–	**2,359**
Other long-term liabilities	36	–	874	543	(21)	**1,432**
Total long-term liabilities	2,942	3,712	13,903	5,855	(7,009)	**19,403**
Total Emera Incorporated equity	8,317	320	6,604	3,303	(10,227)	**8,317**
Non-controlling interest in subsidiaries	–	–	–	22	19	**41**
Total equity	8,317	320	6,604	3,325	(10,208)	**8,358**
Total liabilities and equity	$ 11,627	$ 4,727	$ 23,336	$ 10,106	$ (17,482)	**$ 32,314**
As at December 31, 2017						
Assets						
Current assets	$ 358	$ 30	$ 1,420	$ 891	$ (173)	$ 2,526
Property, plant and equipment	17	–	12,258	4,720	–	16,995
Other assets						
Regulatory assets	–	–	587	686	–	1,273
Goodwill	–	–	5,709	96	–	5,805
Other long-term assets	9,761	4,285	156	3,094	(15,089)	2,207
Total other assets	9,761	4,285	6,452	3,876	(15,089)	9,285
Total assets	$ 10,136	$ 4,315	$ 20,130	$ 9,487	$ (15,262)	$ 28,806
Liabilities and Equity						
Current liabilities	$ 129	$ 12	$ 3,293	$ 714	$ (202)	$ 3,946
Long-term liabilities						
Long-term debt	2,861	4,034	8,468	4,262	(6,485)	13,140
Deferred income taxes	–	4	447	565	7	1,023
Regulatory liabilities	–	–	1,888	354	–	2,242
Other long-term liabilities	34	–	691	550	(24)	1,251
Total long-term liabilities	2,895	4,038	11,494	5,731	(6,502)	17,656
Total Emera Incorporated equity	7,112	265	5,343	2,970	(8,578)	7,112
Non-controlling interest in subsidiaries	–	–	–	72	20	92
Total equity	7,112	265	5,343	3,042	(8,558)	7,204
Total liabilities and equity	$ 10,136	$ 4,315	$ 20,130	$ 9,487	$ (15,262)	$ 28,806

Emera Incorporated

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
As at December 31, 2018						
Net cash provided by (used in) operating activities	$ 191	$ 35	$ 1,266	$ 465	$ (267)	**$ 1,690**
Investing activities						
Additions to property, plant and equipment	(9)	–	(1,687)	(466)	–	**(2,162)**
Net purchase of investments subject to significant influence	–	–	(16)	(33)	–	**(49)**
Other investing activities	(489)	–	3	(65)	572	**21**
Net cash provided by (used in) investing activities	(498)	–	(1,700)	(564)	572	**(2,190)**
Financing activities						
Change in short-term debt, net	–	–	(162)	–	–	**(162)**
Proceeds from long-term debt	–	–	1,174	75	(194)	**1,055**
Retirement of long-term debt	–	–	(716)	(41)	–	**(757)**
Net borrowings (repayments) under committed credit facilities	136	–	(103)	178	110	**321**
Issuance of common and preferred stock	301	–	319	127	(446)	**301**
Dividends paid	(382)	–	(37)	(311)	348	**(382)**
Other financing activities	–	–	–	91	(123)	**(32)**
Net cash provided by (used in) financing activities	55	–	475	119	(305)	**344**
Effect of exchange rate changes on cash, cash equivalents and restricted cash	(4)	2	9	18	–	**25**
Net increase (decrease) in cash, cash equivalents and restricted cash	(256)	37	50	38	–	**(131)**
Cash, cash equivalents and restricted cash, beginning of year	276	21	54	152	–	**503**
Cash, cash equivalents and restricted cash, end of year	$ 20	$ 58	$ 104	$ 190	$ –	**$ 372**

Emera Incorporated

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
As at December 31, 2017						
Net cash provided by (used in) operating activities	$ 195	$ 22	$ 658	$ 1,080	$ (762)	$ 1,193
Investing activities						
Additions to property, plant and equipment	(5)	–	(1,031)	(480)	(13)	(1,529)
Net purchase of investments subject to significant influence	–	–	–	(213)	–	(213)
Other investing activities	(742)	(26)	(5)	1,852	(1,098)	(19)
Net cash provided by (used in) investing activities	(747)	(26)	(1,036)	1,159	(1,111)	(1,761)
Financing activities						
Change in short-term debt, net	–	–	365	(13)	–	352
Proceeds from long-term debt	–	–	147	(31)	13	129
Retirement of long-term debt	–	–	(413)	(55)	15	(453)
Net borrowings (repayments) under committed credit facilities	(30)	–	59	192	9	230
Issuance of common and preferred stock	682	–	134	(2,032)	1,898	682
Dividends paid	(315)	–	(29)	(285)	314	(315)
Other financing activities	290	–	96	(42)	(376)	(32)
Net cash provided by (used in) financing activities	627	–	359	(2,266)	1,873	593
Effect of exchange rate changes on cash, cash equivalents and restricted cash	1	(3)	1	(12)	–	(13)
Net increase (decrease) in cash, cash equivalents and restricted cash	76	(7)	(18)	(39)	–	12
Cash, cash equivalents and restricted cash, beginning of year	200	28	72	191	–	491
Cash, cash equivalents and restricted cash, end of year	$ 276	$ 21	$ 54	$ 152	$ –	$ 503

EMERA LEADERSHIP & BOARD

EMERA LEADERSHIP
(as of March 30, 2019)

Scott Balfour
President and
Chief Executive Officer,
Emera Inc.

Rob Bennett
President and Chief
Executive Officer,
Emera Technologies Inc.

Greg Blunden
Chief Financial Officer,
Emera Inc.

Robert Hanf
Executive Vice President,
Stakeholder Relations
and Regulatory Affairs,
Emera Inc.

Mike Herrin
President and Chief
Operating Officer,
Emera Maine

Karen Hutt
President and
Chief Executive Officer,
Nova Scotia Power

Rick Janega
Chief Operating Officer,
Electric Utilities, Canada,
US Northeast and Caribbean,
Emera Inc.

Sarah MacDonald
Executive Vice President,
Corporate Safety
and Environment,
Emera Inc.

President,
TECO Services Inc.

Bruce Marchand
Chief Legal and Compliance
Officer,
Emera Inc.

Dan Muldoon
Executive Vice President,
Project Development
and Operations Support,
Emera Inc.

Wayne O'Connor
Executive Vice President,
Business Development
& Strategy,
Emera Inc.

Michael Roberts
Chief Human Resources
Officer,
Emera Inc.

Ryan Shell
President,
New Mexico Gas Company

Judy Steele
President and
Chief Operating Officer,
Emera Energy

T.J. Szelistowski
President,
Peoples Gas

Nancy Tower
President and
Chief Executive Officer,
Tampa Electric Company

BOARD OF DIRECTORS
(as of March 30, 2019)

Jackie Sheppard
Chair, Emera Inc.

Former Executive
Vice President,
Corporate & Legal Affairs,
Talisman Energy Inc.,
Calgary, Alberta

Scott Balfour
President and CEO,
Emera Inc.,
Halifax, Nova Scotia

James Bertram
Chair of the Board,
Keyera Corporation,
Calgary, Alberta

Sylvia Chrominska
Former Group Head,
Global Human Resources
and Communications,
The Bank of Nova Scotia,
Toronto, Ontario

Henry Demone
Chairman,
High Liner Foods,
Lunenburg, Nova Scotia

Allan Edgeworth
Former President,
ALE Energy Inc.,
Calgary, Alberta

James Eisenhauer, FCPA, FCA
President,
AGL Group Holdings Ltd.,
Lunenburg, Nova Scotia

Kent Harvey
Former Senior Vice President
and Chief Financial Officer,
PG&E Corporation,
New York, New York

Lynn Loewen, FCPA, FCA
President,
Minogue Medical Inc.,
Westmount, Quebec

Donald Pether
Former Chair of the Board
and Chief Executive Officer,
ArcelorMittal Dofasco Inc.,
Dundas, Ontario

John Ramil
Former President and
Chief Executive Officer,
TECO Energy, Inc.,
Tampa, Florida

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),
Boston, Massachusetts

Jochen Tilk
Former Executive Chair,
Nutrien Ltd.,
Saskatoon, Saskatchewan

SHAREHOLDER INFORMATION

For general inquiries about our Company, please contact our corporate office:

Emera Inc.
P.O. Box 910
Halifax, Nova Scotia B3J 2W5
T: 902.450.0507

Information regarding Company news and initiatives, including our 2018 Annual Report, is also available on our website:
www.emera.com

TRANSFER AGENT

AST Trust Company (Canada)
P.O. Box 2082, Station C
Halifax, NS B3J 3B7
T: 1.877.982.8762
F: 902.420.3242
www.astfinancial.com/ca

INVESTOR SERVICES

T: 902.428.6060 or 1.800.358.1995
F: 902.428.6181
E: investors@emera.com

FINANCIAL ANALYSTS, PORTFOLIO MANAGERS AND INSTITUTIONAL INVESTORS

Vice President, Investor Relations and Treasurer
Ken McOnie
T: 902.428.6945
E: ken.mconie@emera.com

Manager, Investor Relations
Erin Power
T: 902.428.6760
E: erin.power@emera.com

ANNUAL MEETING

The Annual Meeting is scheduled to be held May 15, 2019 at 2:00 p.m. (Atlantic Time) at the Halifax Convention Centre, 1650 Argyle Street, 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, EMA.PR.F and EMA.PR.H
Barbados Stock Exchange (BSE)
Depositary Receipts: EMABDR
The Bahamas International Securities Exchange (BISX)
Depositary Receipts: EMAB

SHARES OUTSTANDING

Common Shares: 234,124,717 (as of December 31, 2018)

DIVIDENDS PAID IN 2018

Emera Inc. paid Common Share dividends of $0.5650 per Common Share in Q1, Q2 and Q3 and $0.5875 in Q4, for an effective annual Common Share dividend rate of $2.2825 per Common Share.

DIVIDEND PAYMENTS IN 2019

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 $0.5875, a Series A First Preferred Share dividend of $0.1597, a Series B First Preferred Share dividend of $0.2206, a Series C First Preferred Share dividend of $0.29506, a Series E First Preferred Share dividend of $0.28125, a Series F First Preferred Share dividend of $0.265625 and a Series H First Preferred Share dividend of $0.30625 was declared and paid on February 15, 2019.

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 up to 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 AST Trust Company (Canada).

QUARTERLY EARNINGS

Quarterly earnings are expected to be announced May, August and November 2019. Year-end results for 2018 were released in February 2019.

www.emera.com