# 2019
# ANNUAL REPORT

Emera


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**COVID-19 UPDATE**

The COVID-19 pandemic is impacting all of us. At Emera, we are focused on keeping our employees and communities safe while continuing to deliver the essential energy needs of our customers. As the pandemic continues, the full impacts are unknown. We expect that the effects of COVID-19 on our sector will not be as severe as other industries, but we know it will have impacts given the changing energy consumption of our commercial and industrial customers. We are also scaling back our capital programs during this time to mitigate the risks to our people and our contractors. We know that the energy we deliver is critical to our customers during these times, especially hospitals and other healthcare services. We are taking active and important steps to protect our team members, particularly those in critical roles, so that we can continue to deliver reliable energy to our customers even if this crisis extends beyond current forecasts. We are committed to keeping our shareholders and communities updated during this critical and evolving situation.

All data is as of December 31, 2019, unless otherwise indicated.

# Why Invest in Emera

**For over a decade, Emera has been focused on safely delivering cleaner, affordable and reliable energy, while ensuring we maintain affordability for customers and deliver long-term value to shareholders.**

All data is as of December 31, 2019, unless otherwise indicated.

## SUPERIOR SHAREHOLDER RETURNS

**~13%**
total shareholder return over the last five years

Representation in the TSX Composite, TSX Capped Utilities, TSX60 and select MSCI and FTSE World indexes

**20 years**
of outperforming the TSX Composite and Capped Utilities indexes

## REGULATED PORTFOLIO

**95%**
of earnings derived from regulated investments

**55%**
of rate base located in Florida

**65%**
of earnings from US operations

## GROWING AND SUSTAINABLE DIVIDEND

**4-5%**
dividend growth target through 2022

**10%**
growth in dividend per share over the last five years

**4.5%**
dividend yield

## VISIBLE GROWTH PLAN*

**$7.5B+**
capital investment plan to drive rate base growth through 2022

**8%+**
rate base growth through 2022, driven by Florida investments

**70%**
of capital program to be invested in Florida

* As of February 2020.

# Emera at a Glance

**From our origins as a single electric utility in Nova Scotia, Emera has grown into an energy leader serving 2.5 million customers in Canada, the US and the Caribbean. Our companies include electric and natural gas utilities, natural gas pipelines, and energy marketing and trading.**

### TAMPA ELECTRIC

Vertically integrated electric utility serving 780,000 customers in West Central Florida.

### PEOPLES GAS

Natural gas utility serving 406,000 customers in Florida.

### NOVA SCOTIA POWER

Vertically integrated electric utility serving 523,000 customers in Nova Scotia.

### NEW MEXICO GAS

Natural gas utility serving 534,000 customers in New Mexico.

### 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 NEW BRUNSWICK

Owns and operates the Brunswick Pipeline, a 145-kilometre natural gas pipeline in New Brunswick.

### EMERA TECHNOLOGIES

A technology company focused on finding new, innovative ways to deliver renewable and resilient energy to customers.

### EMERA NEWFOUNDLAND & LABRADOR

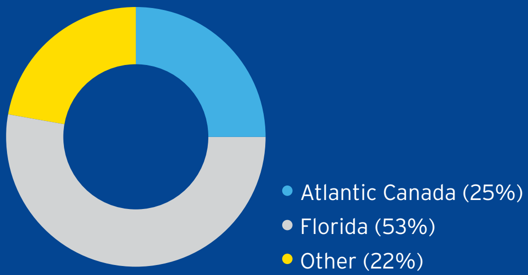
Owns and operates the Maritime Link and manages Emera's investments in associated projects.

* The sale of Emera Maine to ENMAX Corporation closed in March 2020.

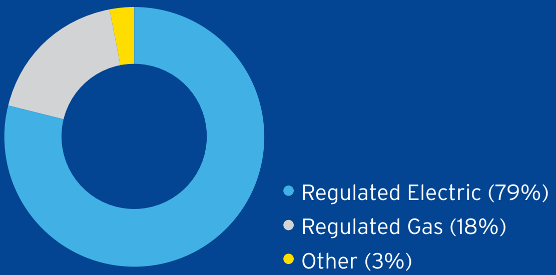
**Adjusted Revenue***

For the year ended December 31, 2019

**By Region**




**By Revenue Type**




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

**As customer demand for lower carbon energy and more choice and control increases, Emera is well positioned to be a leader in building a cleaner energy future while delivering long-term value to shareholders.**

# 2019 Financial Highlights

**5%**

increase in adjusted EPS over the last six years, while our regulated utilities delivered 11% adjusted EPS growth in the same period

**10%**

earnings growth in regulated utilities from 2018 to 2019

**4%**

increase in dividend to **$2.37** in 2019 from **$2.28** in 2018

# 2019 Operational and ESG Highlights

Information is as of December 31, 2019, unless otherwise stated.

## OPERATIONAL

**1,107MW**
installed renewable capacity
Up from 832MW in 2018

**535,000**
smart meters installed across electric utilities
Of a planned 1.4M

**5.8M**
solar panels installed at Tampa Electric since 2016 (as of April 1, 2020)
Investing in an additional 6M panels by end of 2023

## ENVIRONMENTAL

**35%**
reduction in GHG emissions from 2005*
Up from 24% in 2018

**60%**
of our 2020–2022 capital plan is focused on investments in cleaner energy

**18%**
of NSP's energy comes from wind – one of the highest integrations of wind in North America

## COMMUNITY

**$13.4M**
invested in our communities

**42,800 hours**
volunteered by Emera employees in our communities
A 10% increase from 2018

**$470,000**
raised by Emera employees for charitable organizations throughout our communities

## SAFETY AND EMPLOYEES

**1,108**
proactive safety reports for every 100 employees
Up 30% from 2018

**18%**
reduction in OSHA injury rate
Down to 1.08 from 1.29 in 2018

**Top 100 Employer**
in Canada for 2nd consecutive year

## GOVERNANCE

**36%**
of Director Nominees for 2020 AGM are women, including the Chair

**97.4%**
of shareholders voted in favour of Emera's compensation practices in 2019 "Say on Pay" advisory vote

**38%**
of executives at Emera Inc. are women
34% of executives across the Emera group of companies are women

* Undergoing third-party verification.

# Letter from the Chair

## On behalf of Emera's Board of Directors, I am proud of the progress the Emera team made last year in advancing our strategy, strengthening the balance sheet and taking important steps for future growth.

The Board of Directors remains focused on overseeing corporate strategy development and worked closely with the leadership team last year to further position Emera for continued success in a rapidly changing energy industry. We believe that good corporate governance is critical, and the Board is committed to continuing to support Emera's evolving business through ensuring strong governance practices across the business.

In 2019, Emera significantly advanced its strategy of safely delivering cleaner, affordable and reliable energy to customers through large investments in renewable energy and infrastructure improvements to further reduce greenhouse gas (GHG) emissions. The team is also taking important actions to increase reliability for customers.

In 2019, Emera successfully executed its strategic asset sale program to optimize the company's portfolio. The capital from these asset sales is being used to repay debt and to finance the growth in the strongest and highest performing businesses.

As always, we remain focused on delivering shareholder value over the long term. In 2019, the timing of asset sales, the impact of Hurricane Dorian and unfavourable weather conditions for Emera Energy's marketing and trading business all contributed to lower earnings. Despite these factors, Emera's core utilities performed well and are successfully repositioned to continue to deliver strong growth.

Emera's environmental, social and governance (ESG) practices are central to our strategy, culture and overall approach to business. The Board is committed to ensuring transparency and overseeing the risks and opportunities around the material ESG factors that drive long-term value for the company. We understand that investors are increasingly evaluating the progress the company is making on advancing our environmental commitments, social values and strong corporate governance.

We are proud of the contributions we are making to a cleaner energy future, including achieving a 35 per cent reduction in GHG emissions from 2005 levels across Emera in 2019. We have continued our commitment to strong representation of women on our Board and in our businesses. Honouring our commitment to a target of 30 per cent women on our Board, 36 per cent of the Director Nominees for election at our 2020 Annual Meeting of Shareholders are women. Emera's commitment to the communities where we operate is evident in last year's community investment of over $13 million. All of our success is driven by our teams, and once again Emera was named one of Canada's Top 100 Employers in 2019.

> **Emera's environmental, social and governance (ESG) practices are central to our strategy, culture and overall approach to business.**

**Jackie Sheppard**
Chair, Emera Inc. Board of Directors

Emera's 2019 Sustainability Report will be published later this year. Previous reports are available at https://www.emera.com/about-us/our-approach/sustainability.

The Board of Directors is pleased with the progress the company is making on safety. Emera continues to build a strong safety culture with robust safety management systems, policies and demonstrated safety leadership across the business. The team's commitment to safety was evident during the company's response to Hurricane Dorian, which caused tremendous damage on the island of Grand Bahama and in Nova Scotia. On behalf of the Board, thank you to all employees who remained dedicated to safety while working quickly to restore power to customers.

I would like to acknowledge long-time Director Don Pether, who is stepping down this year. Don joined the Emera Board in 2008, bringing with him extensive expertise in international business and a strong commitment to exemplary corporate governance. Don has served on many committees of the Board over the years and his contributions have been countless. On behalf of the entire Board, we wish Don all the best.

These Nova Scotia Power employees represent a growing number of women across Emera working in what were once considered non-traditional roles.

Finally, I would like to thank my Board colleagues for their ongoing commitment to Emera's long-term success. I also thank Scott and the entire team across the business for the important progress made in advancing the strategy, the very strong execution on key projects and the solid results for the year.

To our valued shareholders, thank you for your continued confidence in Emera.

**Jackie Sheppard**
Chair, Emera Inc. Board of Directors

# Letter from the CEO

## Last year was an important year for our business as we continued to advance our strategy of safely delivering cleaner, affordable and reliable energy to our customers.

We also took a number of important steps that repositioned Emera for stronger future growth.

Over the past year, we reviewed our portfolio of companies and redeployed capital to finance the growth in some of our strongest and highest performing businesses. The team successfully executed the sale of the New England Gas plants, the Bayside Generating Plant in New Brunswick and Emera Maine.

Today, we have what I believe to be one of the best portfolios of utility companies in North America. We are now more than 95 per cent regulated, providing a higher quality and more predictable earnings profile. Today, almost 60 per cent of our business is in Florida, and this is expected to grow as approximately 70 per cent of our forecasted capital spending is also in Florida. Our utility operations and assets in Atlantic Canada and Florida now represent 85 per cent of Emera. Our four largest utility investments – Tampa Electric, Peoples Gas, Nova Scotia Power and New Mexico Gas – represent 90 per cent of Emera's business today. These businesses have been driving Emera's growth for the last few years and they are the key contributors to our forecasted 8.2 per cent rate base growth profile over the 2020–2022 period. We also have a stronger balance sheet and a tested strategy that is as relevant, effective and durable today as it has ever been.

### FINANCIAL PERFORMANCE

Overall, we are in a stronger financial position based on the actions we took last year. While our earnings in 2019 were lower than the year before, that was not unexpected. Our 2019 adjusted earnings per share (EPS) was $2.59, down from 2018. Adjusted net income was $621 million compared with $671 million in 2018.

We anticipated this reduction, largely because of the timing of the sale of our gas plants in the first quarter of 2019. This resulted in our gas plants contributing $43 million less in earnings in 2019 as compared to 2018. In addition, 2018 earnings included a one-time benefit related to the change in Florida state tax apportionment factors of $23 million.

Our results for the year were also affected by two unexpected factors: the impacts of Hurricane Dorian and the unfavourable weather conditions experienced by Emera Energy's marketing and trading business. These impacts were essentially offset by strong performance within our continuing utilities, which delivered strong year-over-year adjusted earnings growth of 10 per cent.

Our focus on delivering value for our customers enables us to achieve growth in earnings per share and cash flow per share, which supports our dividend growth and our ultimate goal of strong returns to our shareholders. Over the last five years, Emera has delivered 13 per cent total shareholder return, consistently outperforming the TSX Composite and the TSX Capped Utilities indexes.

### STRATEGY IN ACTION

The trends of decarbonization, decentralization and digitalization are driving unprecedented change in the energy industry. While some see these as potentially disruptive forces, at Emera we see them as opportunities.

We have been strategically focused on safely delivering cleaner, affordable and reliable energy to customers for over a decade. Our investments in cleaner energy generation, in transmission to deliver that cleaner energy and in reliability improvements have been driving our growth for many years. These

> **Emera has proven its ability to drive the transition to cleaner energy in a way and at a pace that does not compromise affordability.**

**Scott Balfour**
President and Chief Executive Officer, Emera Inc.

continue to be the primary drivers of our growth today and for the foreseeable future. Decarbonization and reliability investments represent approximately 60 per cent of our $7.5 billion capital investment profile over the 2020–2022 period.

Energy companies have an important role to play as we all strive toward a cleaner energy future. Decarbonization of our economies and communities depends upon our ability to decarbonize the energy that powers them. As we know, the transition from high-carbon to low-carbon energy requires significant investment. We are making those investments and they are driving our growth. However, the pace and approach to these transition investments must be thoughtful to ensure energy remains both reliable and affordable for customers, today and into the future.

Emera has proven its ability to drive the transition to cleaner energy in a way and at a pace that does not compromise affordability or system reliability. For example, Nova Scotia Power has delivered the fastest transition to cleaner energy in Canada and is on track for 40 per cent of its energy to be from renewable sources by 2021 and for nearly 60 per cent to be non-emitting. NSP's 18 per cent integration of wind generation is among the highest in North America, and it has already achieved reductions in $CO_2$ levels that exceed the targets set by Canada in the COP21 Paris accord. In fact, the team is on track to more than double the reduction target well before the COP21 timeline of 2030. At the same time, during this transition, NSP's non-fuel rates have not increased since 2014.

An aerial view of Lithia Solar in Tampa, Florida, where Khatadin sheep are grazing in the fields to keep the grass short.

In Florida, over the three years since we acquired TECO, Tampa Electric's generation mix has increased from virtually no solar generation, to approximately 594 MW today, representing approximately 5.8 million solar panels. This is the highest proportion of solar generation of any utility in the state of Florida.

Tampa Electric is also retiring coal plants and converting coal units to cleaner, higher efficiency natural gas generation. The $850 million USD Big Bend Modernization project will not only improve the efficiency and further reduce the emission profile of this important generation facility, it will also enable and support additional intermittent solar generation. Together, these investments will deliver a 36 per cent reduction in $CO_2$ emissions at Tampa Electric.

Plans at Tampa Electric now include an additional investment of $800 million USD to build another 600 MW of solar energy by the end of 2023. During this period of significant investment in cleaner, more reliable energy, Tampa Electric customers' bills have continued to be among the lowest in the state and roughly 22 per cent below the national average, remaining relatively unchanged since 2013.

All of these investments are part of our $7.5 billion capital investment plan over the 2020–2022 period, which is driving a highly competitive estimated compound annual growth rate in our rate base of approximately 8.2 per cent. This growth in rate base will drive a growth in earnings and cash flow, and will also support the continued growth of our dividend. These are all important drivers in our goal to deliver growth over time in shareholder value.

While decarbonization and reliability investments represent the largest part of our capital investment profile today, we are also making investments to prepare for a more decentralized and digital future:

- As of mid-February 2020, we've installed 620,000 smart meters across our electric utilities. This technology enables us to provide better information to our customers about their energy use and about process and cost efficiencies that will help ensure affordability for customers.
- In partnership with NB Power, NSP launched a collaborative Smart Grid Innovation Project to look at the evolving system integration of solar generation, battery storage, electric vehicle smart charging and smart thermostat technologies.
- We launched the state of Florida's first shared solar program. Sun Select gives Tampa Electric customers the ability to choose to receive some, or all, of their electricity from the sun, without the need to invest in or install solar panels, or to sign a contract.
- Through Emera Technologies, we have developed a DC-based microgrid system that combines rooftop and community solar generation, with residential and community battery storage. This technology enables the efficient sharing of energy within neighbourhoods that is safer and more reliable than other solutions. The system has now been successfully piloted in partnership with Sandia National Labs at a US Airforce Base. We are now looking to build a commercial path for this "Block Energy" solution, with plans to test this technology, in partnership with utility companies, within residential subdivisions over the next year.

## HURRICANE DORIAN

It is hard to discuss 2019 without mentioning Hurricane Dorian. Even in the face of tremendous personal loss, the team at Grand Bahama Power moved quickly and safely to restore power to customers on the island. Today, all customers that can safely receive power have been reconnected. In Nova Scotia, Dorian knocked out power to more than 400,000 customers, with additional outages in the days that followed. With the largest contingent of crews and storm response personnel in NSP's history, service was restored to more than 65 per cent of affected customers within just 48 hours. This type of dedication reflects the commitment of our team to continually deliver for our customers.

## ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

As you can see above, ESG is central to our strategy. We understand that investors and stakeholders are increasingly looking for information on our progress in these important areas. We are continually working to further integrate strong ESG practices into our overall corporate strategy, risk management, and financial and operational performance. We are also committed to improving our disclosure on material ESG factors that can impact financial performance.

Through our community investment program, we strive to help build stronger, safer and more innovative communities. In 2019, we contributed approximately $13.4 million to charitable and not-for-profit organizations across the communities in which we operate.

We continue to focus on our efforts to be an employer of choice, attracting and retaining the very best people. I am proud of the team at Emera, and proud of the recognition of being named one of Canada's Top 100 Employers for the second consecutive year. We are also committed to ensuring a diverse and inclusive workplace. Today, 38 per cent of executive officers at Emera Inc. are women, while across the entire company, 34 per cent of the executive team are women. While we are making progress, we know we have more to do.

Our full 2019 Sustainability Report will be released later this year. Previous reports are available at https://www.emera.com/about-us/our-approach/sustainability.

## SAFETY

Keeping each other and our communities safe is the most important thing we do at Emera. It's more important than any other business interest. I'm pleased with the team's continued commitment to safety and the progress we are making toward world-class safety. In 2019, our Occupational Safety and Health Association (OSHA) incident rate was the lowest we've seen in years, and our Proactive Incident Reporting rate increased by 30 per cent from 2018. This tells us safety engagement and the recognition of hazards are growing. But this remains a critical focus area as we strive for an Emera where no one gets hurt.

We accomplished a lot in 2019. I believe that Emera has never been stronger or better positioned for growth. Our Board of Directors has provided invaluable guidance and insight during this important time for the company. I thank our Chair, Jackie Sheppard, and the entire Board for their continued support.

Finally, thank you to our team. Our progress would not be possible without you and your unwavering dedication to safely delivering for customers, our communities and each other.

**Scott Balfour**
President and Chief Executive Officer,
Emera Inc.

# FINANCIAL REVIEW

# MANAGEMENT'S DISCUSSION & ANALYSIS

As at February 14, 2020

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 2019 relative to the same quarter in 2018; the full year of 2019 relative to 2018 and selected financial information for 2017; and its financial position as at December 31, 2019 relative to December 31, 2018. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2019. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations. The five new reportable segments are:

- **Florida Electric Utility**, which consists of Tampa Electric;
- **Canadian Electric Utilities**, which includes Nova Scotia Power Inc. and Emera Newfoundland & Labrador Holdings Inc., a holding company with equity investments in NSP Maritime Link Inc. and Labrador-Island Link Limited Partnership;
- **Other Electric Utilities**, which includes Emera Maine and Emera (Caribbean) Incorporated;
- **Gas Utilities and Infrastructure**, which includes Peoples Gas System, New Mexico Gas Company, Inc., SeaCoast Gas Transmission, LLC; Emera Brunswick Pipeline Company Limited and an equity investment in Maritimes & Northeast Pipeline; and
- **Other**, which includes Emera Energy and corporate holding and financing companies. In 2019, the Company completed the sale of assets previously included in this segment, including the sale of Emera Energy's New England Gas Generating ("NEGG") and Bayside facilities, and Emera Utility Services ("EUS") equipment and inventory.

All comparative reporting segment financial information for the three months and year ended December 31, 2018 has been restated with no impact to reported consolidated results.

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

| **Emera Rate-Regulated Subsidiary or 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") |
| 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") |
| Peoples Gas System ("PGS") – Gas Division of TEC | FPSC |
| New Mexico Gas Company, Inc. ("NMGC") | New Mexico Public Regulation Commission ("NMPRC") |
| SeaCoast Gas Transmission, LLC ("SeaCoast") | FPSC |
| Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") | Canadian Energy Regulator ("CER", formerly the National Energy Board) |
| **Equity Investments** | |
| NSP Maritime Link Inc. ("NSPML") | UARB |
| 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") |
| Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP") | CER and FERC |

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Other Electric Utilities and Gas Utilities and Infrastructure 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", "budget", "could", "estimates", "expects", "forecast", "intends", "may", "might", "plans", "projects", "schedule", "should", "targets", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to 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; 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; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty 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.

Emera's investment in rate-regulated businesses is concentrated in Florida and Nova Scotia. These service areas have experienced stable regulatory policies and economic conditions.

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"), and the amount of equity in the capital structure and the return on that equity ("ROE") as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera has a $6.9 billion capital investment plan over the 2020-to-2022 period and the potential for additional capital opportunities of $500 million to $1 billion over the forecast period, resulting in a forecasted rate base growth of 7 per cent through to 2022. This plan includes significant investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. This planned capital investment is being funded primarily through internally generated cash flows and debt raised at the operating company level. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through to 2022. 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 impacted by movements in the US dollar relative to the Canadian dollar and benefit from a weaker Canadian dollar. Emera may hedge both transactional and 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 significant 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 becoming both more affordable and efficient. 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 and further enhance reliability. Emera sees opportunity in these trends. Emera's strategy is to fund investments in renewable and technology assets which protect the environment and benefit customers through fuel or operating cost savings.

For example, significant investments to facilitate the use of renewable and low-carbon energy include the Maritime Link in Atlantic Canada, the ongoing construction of solar generation at Tampa Electric, and the modernization of the Big Bend Power Station at Tampa Electric. Emera's utilities are also investing in reliability projects and replacing aging infrastructure. All of these projects demonstrate Emera's strategy of finding cleaner ways to meet the energy needs of its 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, the revaluation of US non-regulated net deferred income tax assets as a result of US tax reform in Q4 2017 and the GBPC impairment charge recognized in Q4 2019.

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 BLPC and Emera Reinsurance, a captive reinsurance company in the Other segment.

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-t o-market adjustments for evaluation of performance and incentive compensation.

Refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Other Electric Utilities and Other segments, for further details on mark-to-market adjustments.

In Q3 2019, Hurricane Dorian, a category 5 hurricane, struck Grand Bahama Island causing significant damage across the island. In Q4 2019, the Company recognized a non-cash impairment charge due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. Management believes excluding from net income the effect of this charge better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. Refer to the "Significant Items Affecting Earnings", "Developments" and "Financial Highlights – Other Electric Utilities" sections, for further details on this GBPC impairment charge.

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<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 | 2017 |
| Net income attributable to common shareholders | **$ 193** | $ 231 | **$ 663** | $ 710 | $ 266 |
| GBPC impairment charge | **$ (34)** | $ – | **$ (34)** | $ – | $ – |
| Revaluation of US non-regulated deferred income taxes | **$ –** | $ – | **$ –** | $ – | $ (317) |
| After-tax mark-to-market gain | **$ 82** | $ 64 | **$ 76** | $ 39 | $ 59 |
| Adjusted net income attributable to common shareholders | **$ 145** | $ 167 | **$ 621** | $ 671 | $ 524 |
| Earnings per common share – basic | **$ 0.79** | $ 0.98 | **$ 2.76** | $ 3.05 | $ 1.25 |
| Adjusted earnings per common share – basic | **$ 0.60** | $ 0.71 | **$ 2.59** | $ 2.88 | $ 2.46 |

## EBITDA and Adjusted EBITDA

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

The Company's EBITDA and Adjusted EBITDA may not be comparable to the 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<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 | 2017 |
| Net income [(1)] | **$ 192** | $ 231 | **$ 710** | $ 747 | $ 299 |
| Interest expense, net | **181** | 186 | **738** | 713 | 698 |
| Income tax expense | **43** | 40 | **61** | 69 | 520 |
| Depreciation and amortization | **225** | 229 | **903** | 916 | 856 |
| EBITDA | **641** | 686 | **2,412** | 2,445 | 2,373 |
| GBPC impairment charge | **(34)** | – | **(34)** | – | – |
| Mark-to-market gain, excluding income tax and interest | **118** | 94 | **107** | 58 | 78 |
| Adjusted EBITDA | **$ 557** | $ 592 | **$ 2,339** | $ 2,387 | $ 2,295 |

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

# CONSOLIDATED FINANCIAL REVIEW

## SIGNIFICANT ITEMS AFFECTING EARNINGS

### 2019

#### GBPC Hurricane Dorian Restoration

On September 1, 2019, Hurricane Dorian struck Grand Bahama as a Category 5 hurricane, causing significant damage across the island. Emera's 2019 earnings decreased by approximately $62 million ($0.26 per common share), as a result of the impact of the hurricane, as detailed below.

In Q4 2019, Emera recognized a GBPC impairment charge of $34 million, including $30 million related to goodwill due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. This non-cash charge was recorded as a "GBPC impairment charge" in the Consolidated Statements of Income. Refer to note 21 to the consolidated financial statements for the year ended December 31, 2019 for further information.

In addition, GBPC's earnings for the full year decreased by $13 million ($0.05 per common share) due to reduced load as a result of the storm. Finally, Emera recorded a corporate loss of $15 million ($0.06 per common share) in 2019, in the Other segment, for the corporate share of the unrecoverable loss on GBPC's facilities.

Refer to the "Developments" section for further details on Hurricane Dorian.

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

After-tax mark-to-market gains increased $18 million to $82 million in Q4 2019, compared to $64 million in Q4 2018. This increase was due to changes in existing positions on gas contracts, partially offset by higher amortization of gas transportation assets in Q4 2019 in Emera Energy. For the year ended December 31, 2019, after-tax mark-to-market gains increased $37 million to $76 million in 2019, compared to $39 million in 2018. This increase was due to changes in existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019, compared to 2018, partially offset by higher amortization of gas transportation assets in 2019 in Emera Energy.

### 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.

## CONSOLIDATED FINANCIAL HIGHLIGHTS BY BUSINESS SEGMENT

| For the millions of Canadian dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| **Adjusted Net Income** | **2019** | 2018 | **2019** | 2018 | 2017 |
| Florida Electric Utility | **$ 80** | $ 83 | **$ 419** | $ 381 | $ 354 |
| Canadian Electric Utilities | **58** | 44 | **229** | 218 | 203 |
| Other Electric Utilities | **14** | 25 | **76** | 89 | 77 |
| Gas Utilities and Infrastructure | **51** | 43 | **183** | 136 | 109 |
| Other | **(58)** | (28) | **(286)** | (153) | (219) |
| Adjusted net income attributable to common shareholders | **$ 145** | $ 167 | **$ 621** | $ 671 | $ 524 |
| GBPC impairment charge | **(34)** | – | **(34)** | – | – |
| Revaluation of US non-regulated deferred income taxes | **–** | – | **–** | – | (317) |
| After-tax mark-to-market gain | **82** | 64 | **76** | 39 | 59 |
| Net income attributable to common shareholders | **$ 193** | $ 231 | **$ 663** | $ 710 | $ 266 |

The following table highlights the significant changes in adjusted net income from 2018 to 2019:

| For the millions of Canadian dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Adjusted net income – 2018** | **$ 167** | **$ 671** |
| Florida Electric Utility – decreased earnings in Q4 2019 due to unfavourable weather in Florida. Year-over-year increased earnings due to higher contribution from solar investments and customer growth, partially offset by higher depreciation and interest | (3) | 38 |
| Gas Utilities and Infrastructure – increased earnings due to favourable weather in New Mexico, customer growth at PGS and lower depreciation and amortization at PGS | – | 28 |
| NMGC tax benefit related to change in treatment of net operating loss ("NOL") carryforwards, and Q2 2019 recognition of tax reform benefits, of which $8 million relates to 2018 | 8 | 19 |
| Canadian Electric Utilities – NSPI earnings increased due to decreased income taxes and lower pension costs, partially offset by increased depreciation. In addition, year-over-year, increased operating maintenance and general expenses ("OM&G") were partially offset by increased non-fuel revenues. Increased income from equity investments due to timing of revenue and operational costs in NSPML and higher equity investment in LIL | 14 | 11 |
| Gain on sale of property in Florida | – | 10 |
| Transaction costs related to the pending sale of Emera Maine | (1) | (7) |
| 2018 recognition of Florida state tax apportionment benefit | – | (23) |
| Impact of Hurricane Dorian related to GBPC. Refer to the "Significant items Affecting earnings" and "Developments" sections | (12) | (28) |
| Decreased earnings from Emera Energy Generation due to the sale of New England Gas Generating Facilities ("NEGG") and Bayside generation facility | (21) | (43) |
| Decreased earnings at Emera Energy Services | (6) | (49) |
| Other variances | (1) | (6) |
| **Adjusted net income – 2019** | **$ 145** | **$ 621** |

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

| For the<br>millions of Canadian dollars | | | Year ended<br>December 31 |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| Operating cash flow before changes in working capital | **$ 1,598** | $ 1,806 | $ 1,297 |
| Change in working capital | **(73)** | (116) | (104) |
| Operating cash flow | **$ 1,525** | $ 1,690 | $ 1,193 |
| Investing cash flow | **$ (1,617)** | $ (2,190) | $ (1,761) |
| Financing cash flow | **$ 14** | $ 344 | $ 593 |

| As at<br>millions of Canadian dollars | | | December 31 |
|---|---|---|---|
| | **2019** | 2018 | 2017 |
| Total assets | **$ 31,842** | $ 32,314 | $ 28,806 |
| Total long-term debt (including current portion) (1) | **$ 14,180** | $ 15,411 | $ 13,881 |

(1) Excludes Emera Maine balances classified as held for sale as at December 31, 2019. Refer to the "Developments" section and note 4 in the consolidated financial statements for further details.

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

## CONSOLIDATED INCOME STATEMENT HIGHLIGHTS

| For the<br>millions of Canadian dollars<br>(except per share amounts) | | Three months ended<br>December 31 | Variance | | Year ended<br>December 31 | Variance | Year ended<br>December 31 |
|---|---|---|---|---|---|---|---|
| | **2019** | 2018 | | **2019** | 2018 | | 2017 |
| Operating revenues | **$ 1,616** | $ 1,799 | $ (183) | **$ 6,111** | $ 6,524 | $ (413) | $ 6,226 |
| Operating expenses | **1,237** | 1,368 | 131 | **4,768** | 5,126 | 358 | 4,808 |
| Income from operations | **379** | 431 | (52) | **1,343** | 1,398 | (55) | 1,418 |
| Income from equity investments | **36** | 33 | 3 | **154** | 154 | – | 124 |
| Other income (expenses), net | **1** | (7) | 8 | **12** | (23) | 35 | (25) |
| Interest expense, net | **181** | 186 | 5 | **738** | 713 | (25) | 698 |
| Income tax expense | **43** | 40 | (3) | **61** | 69 | 8 | 520 |
| Net income | **192** | 231 | (39) | **710** | 747 | (37) | 299 |
| Net income attributable to common shareholders | **193** | 231 | (38) | **663** | 710 | (47) | 266 |
| GBPC impairment charge | **(34)** | – | (34) | **(34)** | – | (34) | – |
| Revaluation of US non-regulated deferred income taxes | **–** | – | – | **–** | – | – | (317) |
| After-tax mark-to-market gain | **82** | 64 | 18 | **76** | 39 | 37 | 59 |
| Adjusted net income attributable to common shareholders | **$ 145** | $ 167 | $ (22) | **$ 621** | $ 671 | $ (50) | $ 524 |
| Earnings per common share – basic | **$ 0.79** | $ 0.98 | $ (0.19) | **$ 2.76** | $ 3.05 | $ (0.29) | $ 1.25 |
| Earnings per common share – diluted | **$ 0.80** | $ 0.98 | $ (0.18) | **$ 2.76** | $ 3.04 | $ (0.28) | $ 1.24 |
| Adjusted earnings per common share – basic | **$ 0.60** | $ 0.71 | $ (0.11) | **$ 2.59** | $ 2.88 | $ (0.29) | $ 2.46 |
| Dividends per common share declared | **$ –** | $ – | $ – | **$ 2.3750** | $ 2.2825 | $ 0.0925 | $ 2.1325 |
| Adjusted EBITDA | **$ 557** | $ 592 | $ (35) | **$ 2,339** | $ 2,387 | $ (48) | $ 2,295 |

### Operating Revenues

For the fourth quarter of 2019, operating revenues decreased $183 million compared to the fourth quarter in 2018. Absent increased mark-to-market gains of $22 million, operating revenues decreased $205 million due to:

- $130 million decrease in the Other segment due to the sale of NEGG and Bayside;
- $38 million decrease at Florida Electric Utility due to a reduction in base rates as a result of US tax reform and lower clause revenues;
- $21 million decrease at NSPI due to decreased industrial and commercial class sales volume and decreased volume due to weather; and
- $14 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and higher fixed cost commitments for gas transportation and storage assets.

For the year ended December 31, 2019, operating revenues decreased $413 million compared to 2018. Absent increased mark-to-market gains of $48 million, operating revenues decreased by $461 million due to:

- $327 million decrease in the Other segment due to the sale of NEGG and Bayside;
- $137 million decrease at Florida Electric Utility due to lower base rates as a result of US tax reform;
- $84 million decrease in marketing and trading margin at Emera Energy due to less favourable market conditions and higher fixed cost commitments for gas transportation and storage assets; and
- $20 million decrease in PGS due to lower off-system sales and lower base rates as a result of US tax reform, and lower clause-related revenues at PGS and NMGC.

These impacts were partially offset by increases of:

- $65 million at Florida Electric Utility as a result of a weaker Canadian dollar and higher base revenues related to in-service of solar generation projects and customer growth; and
- $41 million at Gas Utilities and Infrastructure as a result of NMGC's recognition of tax reform benefits from January 1, 2018 to June 30, 2019, favourable weather in New Mexico, customer growth at PGS and the impact of a weaker Canadian dollar.

### Operating Expenses

For the fourth quarter of 2019, operating expenses decreased $131 million compared to the fourth quarter of 2018. Absent the $34 million GBPC impairment charge, operating expenses decreased by $165 million due to:

- $96 million decrease in the Other segment primarily due to the sale of NEGG and Bayside;
- $34 million decrease at Florida Electric Utility as a result of decreased OM&G due to the regulatory agreement to net storm costs and tax reform benefits in 2018 and lower fuel costs;
- $17 million decrease at Gas Utilities and Infrastructure due to lower commodity costs in PGS and New Mexico; and
- $16 million decrease at Canadian Electric Utilities primarily due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment, partially offset by increased fuel for generation and purchased power and depreciation.

For the year ended December 31, 2019, operating expenses decreased $358 million compared to 2018. Absent decreased mark-to-market gains of $7 million, and the $34 million GBPC impairment charge, operating expenses decreased $399 million due to:

- $262 million decrease in the Other segment as a result of the sale of NEGG and Bayside;
- $126 million decrease at Florida Electric Utility as a result of decreased OM&G expenses due to the regulatory agreement to net storm costs and tax reform benefits in 2018 and lower fuel costs;
- $48 million decrease at Gas Utilities and Infrastructure due to lower commodity costs in PGS and New Mexico; and
- $44 million decrease at Canadian Electric Utilities primarily due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment.

These impacts were partially offset by an increase of:

- $63 million at Canadian Electric Utilities primarily due to increased fuel costs as a result of commodity pricing, higher OM&G and higher depreciation.

### Other Income (Expenses), Net

The increase in other income (expenses), net for the fourth quarter in 2019 was primarily due to lower pension costs at NSPI, partially offset by the corporate loss recorded by Emera for the corporate share of the unrecoverable loss on GBPC facilities resulting from the impact of Hurricane Dorian, and transaction costs for the pending sale of Emera Maine. For the year ended December 31, 2019, absent increased mark-to-market gains, the increase was also due to the gain on sale of property in Florida.

### Interest Expense

Interest expense, net for the fourth quarter in 2019 was consistent with the same period in 2018. The increase in interest expense, net for the year ended December 31, 2019, compared to 2018 was primarily due to higher borrowings at Florida Electric Utility and a weaker Canadian dollar.

### Income Tax Expense

Income tax expense for the fourth quarter and for the year ended December 31, 2019, was consistent with the same periods in 2018.

### Net Income and Adjusted Net Income Attributable to Common Shareholders

For the fourth quarter of 2019, net income attributable to common shareholders was favourably impacted by the $18 million increase in after-tax mark-to-market gains, primarily related to Emera Energy and unfavourably impacted by the GBPC impairment charge of $34 million. Absent favourable mark-to-market changes and the GBPC impairment charge, adjusted net income attributable to common shareholders decreased $22 million. The decrease was due to lower contributions from Emera Energy (which includes lower contribution due to the sale of NEGG in Q1 2019) and the impact of Hurricane Dorian related to GBPC, partially offset by higher contributions from Canadian Electric Utilities and Gas Utilities and Infrastructure.

For the year ended December 31, 2019, net income attributable to common shareholders was favourably impacted by the $37 million increase in after-tax mark-to-market gains primarily related to Emera Energy and unfavourably impacted by the GBPC impairment charge of $34 million. Absent favourable mark-to-market changes and the GBPC impairment charge, adjusted net income attributable to common shareholders decreased $50 million. The decrease was due to lower contributions from Emera Energy (which includes the lower contribution due to the sale of NEGG in Q1 2019), the 2018 recognition of Florida state tax apportionment benefits, the impact of Hurricane Dorian related to GBPC and transaction costs related to the pending sale of Emera Maine. These were partially offset by higher contribution from Florida Electric Utility, the impact of a weaker Canadian dollar, NMGC's recognition of tax reform benefits, increased contribution from the Gas Utilities and Infrastructure segment and a gain on sale of property in Florida.

### Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share – basic were lower for the fourth quarter and the year ended December 31, 2019 due to decreased earnings as discussed above and the impact of the increase in the weighted average 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 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/US exchange rates for 2019 and 2018 are as follows:

| | Three months ended December 31 | | | | Year ended December 31 | | | |
|---|---|---|---|---|---|---|---|---|
| | | **2019** | | 2018 | | **2019** | | 2018 |
| Weighted average CAD/USD exchange rate | **$** | **1.32** | $ | 1.32 | **$** | **1.33** | $ | 1.30 |
| Period end CAD/USD exchange rate | **$** | **1.30** | $ | 1.36 | **$** | **1.30** | $ | 1.36 |

CAD exchange rates decreased earnings by $1 million and had minimal impact on adjusted earnings in Q4 2019, compared to Q4 2018. Weakening of the CAD increased earnings and adjusted earnings by $13 million in 2019, compared to 2018.

Consistent with the Company's risk management policies, Emera partially manages currency risks through matching US denominated debt to finance its US operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. 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 | | | |
|---|---|---|---|---|---|---|---|---|
| | | **2019** | | 2018 | | **2019** | | 2018 |
| Florida Electric Utility | **$** | **61** | $ | 64 | **$** | **316** | $ | 294 |
| Other Electric Utilities | | **10** | | 20 | | **57** | | 69 |
| Gas Utilities and Infrastructure (1) | | **33** | | 26 | | **115** | | 83 |
| | | **104** | | 110 | | **488** | | 446 |
| Other segment (2) | | **(28)** | | (27) | | **(159)** | | (82) |
| **Total** (3) | **$** | **76** | $ | 83 | **$** | **329** | $ | 364 |

(1) Includes US dollar net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's US dollar adjusted net income from Emera Energy Services, NEGG and Bear Swamp and interest expense on Emera Inc.'s US dollar denominated debt.
(3) Amounts above do not include the impact of mark-to-market or the GBPC impairment charge.

## BUSINESS OVERVIEW AND OUTLOOK

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations.

The five new reportable segments are:

- Florida Electric Utility;
- Canadian Electric Utilities;
- Other Electric Utilities;
- Gas Utilities and Infrastructure; and
- Other.

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, prudent management of operating costs, 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.

## FLORIDA ELECTRIC UTILITY

Florida Electric Utility consists of Tampa Electric, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. Tampa Electric has approximately $9 billion USD of assets and approximately 779,000 customers at December 31, 2019. Tampa Electric owns 5,641 MW of generating capacity, of which 73 per cent is natural gas-fired, 19 per cent is coal and 8 per cent is solar. Tampa Electric owns 2,165 kilometres of transmission facilities and 18,990 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.

Tampa Electric anticipates earning within its allowed ROE range in 2020 and expects rate base and earnings to be higher than 2019. Tampa Electric expects customer growth rates in 2020 to be consistent with 2019, reflective of economic growth in Florida. Assuming normal weather in 2020, Tampa Electric sales volumes are expected to be consistent with 2019, which benefited from favourable weather.

On December 10, 2019, the FPSC approved Tampa Electric's petition to reduce base rates and charges reflecting reduction of the state income tax rate from 5.5 per cent to 4.46 per cent retroactive from January 1, 2019. The base rate reduction of approximately $5 million USD due to customers is subject to true-up, and the actual rate reduction may vary from year to year. In addition, in January 2020, Tampa Electric refunded $12 million USD to customers as a result of the final settlement agreement related to the netting of Hurricane Irma storm costs and 2018 US tax reform benefits.

On October 3, 2019, the FPSC issued a rule to implement a storm protection cost recovery clause. This new clause provides a process for Florida investor-owned utilities, including Tampa Electric, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Subject to final approval of the FPSC rule, Tampa Electric expects to file a storm protection plan with the FPSC in Q2 2020.

As of December 31, 2019, Tampa Electric has invested approximately $820 million USD in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). Tampa Electric expects to invest an additional $30 million USD in these projects through 2021. Allowance for funds used during construction ("AFUDC") is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 554 MW or $96 million USD annually in estimated revenue requirements for in-service projects. Tampa Electric expects to file its final SoBRA petition for the January 1, 2021 tranche in 2020. Tampa Electric also intends to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects with targeted in-service dates during 2021 through 2023.

Tampa Electric expects to invest approximately $850 million USD through 2023 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. As of December 31, 2019, Tampa Electric has invested approximately $275 million USD in this modernization project. AFUDC is being earned on this project during construction.

In 2020, capital expenditures in the Florida Electric Utility segment are expected to be approximately $1.0 billion USD (2019 – $1.1 billion USD), including AFUDC. Capital projects include solar investments, continuation of the modernization of the Big Bend Power Station, which received final state approval on July 25, 2019, storm hardening investments, and advanced metering infrastructure ("AMI").

## CANADIAN ELECTRIC UTILITIES

Canadian Electric Utilities includes NSPI, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia; and ENL, a holding company with equity investments in NSPML and LIL, two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.

## NSPI

With approximately $5.5 billion of assets and approximately 523,000 customers, NSPI 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 545 MW of capacity. NSPI will have an increase in energy from renewable sources upon delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project. Delivery of the NS Block is anticipated to commence in mid-2020. 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 2020 and expects rate base and earnings to be higher than 2019. Assuming normal weather in 2020, NSPI sales volumes are expected to be higher. On December 6, 2019, the UARB approved NSPI's three-year fuel stability plan which results in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. These rates include recovery of Maritime Link costs (discussed in the "ENL – NSPML" section below).

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

The Government of Canada has laws and regulations that would compel the closure of coal plants before the end of their economic life and at the latest by 2030. The Canada-Nova Scotia Equivalency Agreement allows NSPI to achieve compliance with federal GHG emissions regulations through 2029 by meeting provincial legislative and regulatory requirements, as these requirements are deemed to be equivalent to the federal regulations. Efforts are now focused on the development of an Equivalency Agreement for 2030 and beyond recognizing equivalent outcomes between federal and provincial environmental laws and regulations. The Province's Bill 213, "*The Sustainable Development Goals Act*", was enacted in October 2019, and includes a goal of net-zero GHG emissions by 2050. NSPI will continue to work with the provincial government on its carbon reduction goals.

NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations in 2019 and expects to receive its 2020 granted emissions allowances in Q1 2020. These 2020 allowances will be used in 2020 or allocated within the initial four-year compliance period that ends in 2022. At December 31, 2019, NSPI is on track to meet the requirements of the program. NSPI anticipates that any prudently incurred costs required to comply with the Government of Canada's laws and regulations, and the Nova Scotia Cap-and-Trade Program Regulations, will be recoverable under NSPI's regulatory framework.

Nova Scotia's Air Quality Regulations (the "Regulations") with respect to sulphur dioxide ("$SO_2$") emissions have been driving a steady decrease in $SO_2$ emissions since 2005. The current Regulations call for another round of decreases starting in 2020. Given the delay with Muskrat Falls, the provincial government has amended regulations for adjusted emission limits for 2020 through 2022 in order to avoid significant rate increases for customers, while continuing Nova Scotia's downward trend with $SO_2$ emissions. NSPI incorporated the impact of these changes into the UARB-approved fuel stability plan for this three-year period.

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 to further advance its "Coal to Clean" strategy. NSPI achieved carbon dioxide reductions of over 30 per cent from 2005 levels, exceeding the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change targets for a reduction of 30 per cent from 2005 levels by 2030. NSPI is on track to achieve reductions in carbon dioxide of over 55 per cent by 2030.

In 2020, NSPI expects to invest approximately $375 million (2019 – $396 million), including AFUDC, in capital projects to support system reliability, including hydroelectric infrastructure renewal projects and AMI.

## ENL

### NSPML

Through its subsidiary, NSPML, ENL has invested $1.8 billion of equity, debt and working capital, including $209 million of AFUDC, in development of the Maritime Link Project. This investment consists of $554 million in equity, comprised of $452 million in equity contributed and $102 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 and 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, which is anticipated in the second half of 2020.

Equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML'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 30 per cent.

On November 27, 2019, the UARB approved NSPML's interim assessment for recovery from NSPI of 2020 Maritime Link costs of approximately $145 million (2019 – $111 million). The total recovery of $145 million includes approximately $115 million of operating and maintenance, debt financing and equity financing costs, and approximately $30 million for depreciation and amortization of financing costs. This payment is subject to a holdback of up to $10 million. Recovery of the $115 million of operating and maintenance, debt financing and equity financing costs began on January 1, 2020. Beginning June 1, 2020, recovery of the $30 million of depreciation and amortization of financing costs will be included in NSPI customer rates, with payment of this recovery to NSPML to begin on the earlier of the confirmation of delivery of the NS Block and November 1, 2020. NSPML expects to file a final cost assessment with the UARB in 2020.

In 2020, NSPML expects to invest approximately $20 million (2019 – $28 million) in capital.

### 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.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera's current equity investment is $579 million, comprised of $410 million in equity contribution and $169 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million after all Lower Churchill projects, including Muskrat Falls, are completed. Nalcor is forecasting these projects to be completed in the second half of 2020.

Cash earnings and return of equity are forecasted by Nalcor to begin in Q4 2020, and until that point Emera will continue to record AFUDC earnings.

Equity earnings from NSPML and LIL are expected to be higher in 2020, compared to 2019. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

## OTHER ELECTRIC UTILITIES

Other Electric Utilities includes Emera Maine, a regulated transmission and distribution electric utility in the state of Maine, and Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include BLPC, a vertically integrated regulated electric utility on the island of Barbados, GBPC, a vertically integrated regulated electric utility on Grand Bahama Island, and a 51.9 per cent interest in Domlec, a vertically integrated regulated electric utility on the island of Dominica. ECI also holds a 19.1 per cent interest in Lucelec, a vertically integrated regulated electric utility on the island of St. Lucia which is accounted for on the equity basis.

On March 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in early 2020, subject to MPUC approval. Refer to the "Developments" section for further details. As a result of the pending sale, Emera Maine's assets and liabilities were classified as held for sale in Q1 2019.

### Emera Maine

With approximately $1.3 billion USD of assets and approximately 159,000 customers, 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 48 per cent of Emera Maine's operating revenue represents distribution operations, 47 per cent is associated with transmission operations and 5 per cent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

### BLPC

With approximately $420 million USD of assets and approximately 131,000 customers, BLPC owns 266 MW of generating capacity, of which 96 per cent is oil-fired and 4 per cent is solar. The utility has an additional 12 MW of capacity from rental units. 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 17,800 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. In January 2020, the GBPA approved GBPC's regulated return on rate base of 8.34 per cent for 2020 (2019 – 8.44 per cent).

### Domlec

Domlec serves approximately 31,000 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 471 kilometres of transmission facilities and 697 kilometres of distribution facilities. Domlec's approved regulated return on rate base is 15.0 per cent.

### Other Electric Utilities Outlook

Other Electric Utilities' earnings are expected to increase over the prior year due to the GBPC impairment charge recognized in 2019 and higher earnings in 2020 from the Caribbean utilities, partially offset by lower earnings contribution from Emera Maine as a result of the expected sale in early 2020. For the Caribbean, GBPC's earnings are expected to increase as load continues to recover after Hurricane Dorian (discussed below), and earnings from both BLPC and Domlec are expected to be comparable to 2019.

On September 1, 2019, Hurricane Dorian struck Grand Bahama Island causing significant damage across the island. GBPC sustained damage to its generation, transmission and distribution assets. GBPC has restored power to all customers who have requested power and are able to receive it and as of December 31, 2019, power was restored to approximately 92 per cent of its customers. Post-hurricane load is down approximately 13 per cent. Management anticipates that demand will recover to pre-storm levels by the end of 2021. Refer to the "Developments" section for further details.

The Government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. BLPC is negotiating the terms of the new licenses under the amended legislation.

In 2020, capital expenditures in the Other Electric Utilities segment are expected to be approximately $130 million USD (including investment in Emera Maine for the first quarter only) (2019 – $150 million USD). ECI's utilities are forecasting capital investment in more efficient and cleaner sources of generation, including renewables and battery storage. In early February 2020, BLPC completed the installation of 15 MW of additional generation. BLPC expects to complete the installation of a 33 MW diesel engine by mid-2020. This 33 MW plant is expected to increase efficiency and bridge BLPC's transition to increased renewable sources of generation. Emera Maine expects to invest primarily in transmission and distribution projects supporting normal system reliability.

## GAS UTILITIES AND INFRASTRUCTURE

Gas Utilities and Infrastructure includes PGS, a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida; NMGC, a regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico; SeaCoast, a regulated intrastate natural gas transmission company offering services in Florida; Brunswick Pipeline, a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern United States; and Emera's non-consolidated investment in M&NP.

### Peoples Gas System

With approximately $1.6 billion USD of assets and approximately 406,000 customers, the PGS system includes approximately 21,730 kilometres of natural gas mains and 12,070 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2.1 billion therms in 2019.

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. The bottom of the range will increase to 9.75 per cent in 2021, absent a rate case filing for that year. An ROE of 10.75 per cent is used for the calculation of return on investments for clauses.

### New Mexico Gas Company, Inc.

With approximately $1.1 billion USD of assets and approximately 534,000 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 2,488 kilometres of transmission lines and 17,223 kilometres of distribution lines. Annual natural gas throughput was approximately 969 million therms in 2019.

The approved ROE for NMGC is 9.1 per cent, on an allowed equity capital structure of 52 per cent. On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019. The new rates are being phased in over two years and are expected to result in an annual revenue increase of approximately $3 million USD. The NMPRC also approved the utility's weather adjustment mechanism.

### Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure earnings are anticipated to be lower than 2019 due to decreased earnings from NMGC as a result of the recognition of tax reform benefits, and the approved change in treatment of NOL carryforwards in 2019.

Earnings from PGS are expected to be consistent with 2019. PGS expects customer growth rates in 2020 to be consistent with 2019, reflecting economic growth in Florida and the optimization of existing opportunities as the utility increases its market penetration in Florida. Assuming normal weather in 2020, PGS sales volumes are expected to increase at a higher rate in 2020, as 2019 energy sales were impacted by unfavourable weather. Despite these expected revenue increases, significant capital investments and related growth in rate base is resulting in PGS anticipating it will earn below its allowed ROE range in 2020. Consistent with its FPSC-approved 2018 tax reform settlement agreement, PGS is permitted to initiate a general base rate proceeding during 2020, regardless of its earned ROE at the time, provided the new rates do not become effective before January 1, 2021. Therefore, as a result of forecasted revenue requirements being higher than what is in current rates, on February 7, 2020, PGS notified the FPSC that it is planning to file a base rate proceeding in April 2020 for new rates effective January 2021.

NMGC anticipates earning at or near its approved ROE in 2020 and expects rate base to be higher than 2020. Customer growth rates are expected to be consistent with 2019, reflecting expectations for housing starts and new connections. Assuming normal weather in 2020, NMGC sales volumes are expected to decrease, as 2019 energy sales benefited from favourable weather in the first half of the year.

On December 23, 2019, NMGC filed a future year base rate case with the NMPRC for new rates effective January 2021. The proposed new rates reflect the recovery of capital investment in pipelines and related infrastructure. The estimated annual incremental revenue requirement is approximately $13 million USD. A decision from the NMPRC is expected in late 2020.

In 2020, capital expenditures in the Gas Utilities and Infrastructure segment are expected to be approximately $580 million USD (2019 – $331 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC will complete the Santa Fe Mainline Looping project in 2020 and will continue to invest in system improvements.

In 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 is constructing and will 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 approximately $110 million USD, with $35 million USD invested through 2019 and $48 million USD expected to be invested in 2020. SeaCoast is also jointly developing the 26.5 mile, 16-inch Callahan Pipeline with Peninsula Pipeline Co., an affiliate of Florida Public Utilities. This pipeline is expected to go into service in 2021. SeaCoast will provide long-term firm gas transportation service to PGS in the northeast Florida area under a long-term transportation agreement between SeaCoast and PGS, which was approved by the FPSC in November 2019. SeaCoast's portion of the estimated capital investment in the Callahan Pipeline is projected to be approximately $32 million USD, with $6 million USD invested through 2019 and approximately $26 million USD expected to be invested in 2020.

## OTHER

The Other segment includes those business operations that in a normal year are below the required threshold for reporting as separate segments; and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments.

Business operations in Other include Emera Energy, which consists of:

- Emera Energy Services ("EES"), a wholly owned physical energy marketing and trading business;
- Brooklyn Power Corporation ("Brooklyn Energy'), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; 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.

In 2019, the Company completed the sale of assets previously reported in this segment including the sale of its NEGG and Bayside facilities in March 2019 and the sale of its Emera Utility Services equipment and inventory in December 2019.

Corporate items included in the Other segment are certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings recorded in "Intercompany revenue" and interest expense on corporate debt in both Canada and the US. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera's subsidiaries and investments.

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. The business is generally expected to deliver annual 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.

The Other segment is expected to contribute positively to earnings in 2020 due to the sale of Emera Maine, with a material gain expected to be recognized in earnings at closing. Absent this gain, the adjusted net loss from the Other segment is expected to decrease over the prior year, primarily due to lower corporate costs and expected EES contribution within its normal range in 2020, partially offset by the 2019 sale of NEGG. Corporate costs are expected to be lower due to decreased interest expense related to debt maturities and 2019 recognition of the corporate share of the unrecoverable loss related to the impact of Hurricane Dorian on GBPC.

In 2020, capital expenditures in the Other segment are expected to be approximately $74 million (2019 – $60 million), including investment in contracted energy infrastructure.

# CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2018 and December 31, 2019 include:

| millions of Canadian dollars | Total Increase (Decrease) | Classification of Emera Maine as Held for Sale (1) | Other Increase (Decrease) | Explanation of Other Increase (Decrease) |
|---|---|---|---|---|
| **Assets** | | | | |
| Cash and cash equivalents | **$ (94)** | **$ –** | **$ (94)** | Decreased due to additions of property, plant and equipment and payment of common and preferred dividends. These were partially offset by cash from operations, proceeds from disposal of assets, changes in borrowings and the issuance of common shares. |
| Derivative instruments (current and long-term) | **(80)** | **–** | **(80)** | Decreased due to settlement of derivatives and lower commodity prices at NSPI. |
| Regulatory assets (current and long-term) | **(17)** | **(138)** | **121** | Increased due to deferred income tax regulatory asset and deferrals related to derivative instruments at NSPI, partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates. |
| Receivables and other assets (current and long-term) | **(125)** | **(78)** | **(47)** | No significant change after removing impact of held for sale classification. |
| Assets held for sale (current and long-term), net of liabilities | **(117)** | **691** | **(808)** | Decreased due to completion of the sale of the NEGG facilities. |
| Property, plant and equipment, net of accumulated depreciation and amortization | **(545)** | **(1,293)** | **748** | Increased due to additions at Tampa Electric, PGS, NMGC and NSPI partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates. |
| Goodwill | **(478)** | **(148)** | **(330)** | Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries and the GBPC impairment charge. |
| **Liabilities and Equity** | | | | |
| Short-term and long-term debt (including current portion) | **(880)** | **(516)** | **(364)** | Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and repayment of Emera US Finance LP USD note upon maturity, partially offset by proceeds from Emera's non-revolving credit facility, and issuances at Tampa Electric, NSPI and Emera Maine. |
| Accounts payable | **(171)** | **(35)** | **(136)** | Decreased due to lower commodity prices at Emera Energy, lower cash collateral positions at NSPI and Emera Energy, and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries. |
| Deferred income tax liabilities, net of deferred income tax assets | **(46)** | **(204)** | **158** | Increased primarily due to tax deductions in excess of accounting depreciation related to property, plant, and equipment. |
| Regulatory liabilities (current and long-term) | **(429)** | **(156)** | **(273)** | Decreased primarily due to the effect of a stronger CAD on the translation of Emera's foreign affiliates and deferrals related to derivative instruments, fuel adjustment mechanism and cost of removal at NSPI. |
| Pension and post-retirement liabilities | **(181)** | **(73)** | **(108)** | Decreased due to higher returns and the effect of a stronger CAD on the translation of Emera's foreign affiliates. |
| Common stock | **400** | **–** | **400** | Increased due to the dividend reinvestment plan, increase in options exercised and shares issued under Emera's at-the-market equity program ("ATM Program"). |
| Accumulated other comprehensive income | **(243)** | **–** | **(243)** | Decreased due to the effect of a stronger CAD on the translation of Emera's foreign subsidiaries. |
| Retained earnings | **98** | **–** | **98** | Increased due to net income in excess of dividends paid. |

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to the "Developments" section and note 4 in the consolidated financial statements for further details.

# DEVELOPMENTS

## HURRICANE DORIAN

In September 2019, Hurricane Dorian impacted GBPC, NSPI and Tampa Electric, as discussed below.

### GBPC

On September 1, 2019, Dorian struck Grand Bahama as a Category 5 hurricane, with sustained winds of approximately 285 kilometres per hour. The hurricane stalled over the island for several days, causing significant damage to, or destruction of, homes and businesses served by GBPC. GBPC's generation, transmission and distribution assets sustained damage, including the effect of flooding that resulted from storm surge and rain. All 19,300 of GBPC's customers lost power following the storm. As of December 31, 2019, power was restored to all customers who were able to receive power, or approximately 17,800 customers.

#### Earnings Impact

Emera's 2019 earnings decreased by approximately $62 million as a result of the impact of the hurricane, reflecting an impairment charge of $34 million, including $30 million related to goodwill, $13 million related to loss of load and $15 million for the corporate share of the unrecoverable loss on GBPC's facilities. Refer to "Significant Items Affecting Earnings" for further details.

#### Balance Sheet Impact

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are self-insured. It is currently estimated that restoration costs for GBPC self-insured assets will be approximately $15 million USD. In January 2020, the GBPA approved the recovery of these costs through rates over a five-year period. Approximately $12 million USD of these estimated costs were incurred in 2019, and recorded as a regulatory asset.

As a result of the damage caused by Hurricane Dorian, the Company completed an asset impairment analysis in Q4 2019. Property, plant and equipment and inventory with a book value of approximately $18 million USD was determined to be impaired and was reclassified as a regulatory asset. GBPC recorded an offsetting insurance receivable of $15 million USD against this regulatory asset. It is anticipated that the regulatory asset balance of $3 million USD remaining at December 31, 2019 will also be recovered through insurance.

### NSPI

On September 7, 2019, Dorian struck Nova Scotia with sustained hurricane force winds of over 100 kilometres per hour and peak gusts of approximately 155 kilometres per hour. The storm caused widespread damage to NSPI's transmission and distribution system and, at the height of the storm, approximately 412,000 customers were affected. By September 10, 2019, power had been restored to 80 per cent of those affected, and all customers were restored by September 17, 2019. NSPI incurred $40 million of storm restoration costs of which $24 million was capitalized to property, plant and equipment, with the remaining $16 million charged to OM&G expense. There was no overall impact on NSPI earnings as NSPI's increased storm costs were offset by some of the excess non-fuel revenues that were recorded in 2019.

### Tampa Electric

In preparation for Hurricane Dorian, Tampa Electric incurred approximately $8 million USD in storm costs. There was no impact to Tampa Electric earnings as these costs were charged to Tampa Electric's storm reserve regulatory liability. As of December 31, 2019, the storm reserve regulatory liability balance was $62 million ($48 million USD).

## AT-THE-MARKET EQUITY PROGRAM

On July 11, 2019, Emera established an ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was established under a prospectus supplement to the Company's short-form base shelf prospectus which expires on July 14, 2021. During 2019, approximately 1.8 million common shares were issued under the ATM Program at an average price of $56.56 per share for gross proceeds of $100 million ($98.7 million net of issuance costs). As at December 31, 2019, an aggregate gross sales limit of $500 million remains available for issuance under the ATM program.

### INCREASE IN COMMON DIVIDEND

On September 27, 2019, Emera's Board of Directors approved an increase in the annual common share dividend rate to $2.45 from $2.35. The first payment was effective November 15, 2019. Emera extended its four to five per cent annual dividend growth rate target through to 2022.

### REMOVAL OF LEGISLATIVE RESTRICTION ON NON-CANADIAN RESIDENT OWNERSHIP OF EMERA SHARES

On April 12, 2019, amendments to the *Nova Scotia Power Privatization Act* and the *Nova Scotia Power Reorganization (1998) Act* were enacted, removing the legislative restriction preventing non-Canadian residents from holding more than 25 per cent of Emera voting shares, in aggregate. On July 11, 2019, shareholders passed a special resolution to immediately amend the Company's articles of association to remove this restriction.

### SALE OF EMERA ENERGY'S NEW ENGLAND GAS AND BAYSIDE GENERATING FACILITIES

On March 29, 2019, Emera completed the sale of its three NEGG facilities for cash proceeds of $799 million ($598 million USD), including working capital adjustments. On March 5, 2019, the Company sold its Bayside facility for cash proceeds of $46 million. An immaterial loss was recognized on these dispositions. Proceeds from the sales were used to reduce corporate debt and support capital investment opportunities within Emera's regulated utilities.

### PENDING SALE OF EMERA MAINE

On March 25, 2019, Emera announced the sale of Emera Maine for a total enterprise value of approximately $1.3 billion USD including cash proceeds of $959 million USD, transferred debt and a working capital adjustment on close. The transaction is expected to close in early 2020, subject to the approval of the MPUC. All other required regulatory approvals have been received.

A material gain on the sale is expected to be recognized in earnings at closing. Proceeds from the sale will be used to support capital investment opportunities within Emera's regulated utilities and to reduce corporate debt.

### APPOINTMENTS

#### Executive

Effective October 21, 2019, Karen Hutt was appointed Executive Vice President, Strategy & Business Development for Emera. Most recently, Ms. Hutt was President and CEO of NSPI.

Effective October 21, 2019, Wayne O'Connor was appointed President and CEO of NSPI. Most recently, Mr. O'Connor was Executive Vice President, Strategy & Business Development for Emera.

## OUTSTANDING COMMON STOCK DATA

| **Common stock**<br>**Issued and outstanding:** | millions of shares | millions of Canadian dollars |
|---|---|---|
| Balance, December 31, 2017 | 228.77 | $ 5,601 |
| Conversion of Convertible Debentures | 0.01 | - |
| Issuance of common stock | 0.45 | 22 |
| Issued for cash 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 |
| Conversion of Convertible Debentures | 0.03 | 1 |
| Issuance of common stock (1) | 1.77 | 99 |
| Issued for cash under Purchase Plans at market rate | 3.99 | 202 |
| Discount on shares purchased under Dividend Reinvestment Plan | - | (7) |
| Options exercised under senior management stock option plan | 2.57 | 104 |
| Employee Share Purchase Plan | - | 1 |
| **Balance, December 31, 2019** | **242.48** | **$ 6,216** |

(1) As at December 31, 2019, a total of 1.77 million common shares have been issued through Emera's ATM Program at an average price of $56.56 per share for gross proceeds of $100 million ($98.7 million net of issuance costs).

As at February 11, 2020, the amount of issued and outstanding common shares was 242.6 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, 2019 was 242.9 million (2018 – 234.9 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2019 was 239.9 million (2018 – 233.0 million).

# FINANCIAL HIGHLIGHTS

## FLORIDA ELECTRIC UTILITY

All amounts are reported in USD, unless otherwise stated.

| For the<br>millions of US dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Operating revenues – regulated electric | **$ 473** | $ 501 | **$ 1,965** | $ 2,066 |
| Regulated fuel for generation and purchased power | **143** | 155 | **582** | 637 |
| Contribution to consolidated net income | **$ 61** | $ 64 | **$ 316** | $ 294 |
| Contribution to consolidated net income – CAD | **$ 80** | $ 83 | **$ 419** | $ 381 |
| Contribution to consolidated earnings per common share – basic – CAD | **$ 0.33** | $ 0.35 | **$ 1.75** | $ 1.64 |
| Net income weighted average foreign exchange rate – CAD/USD | **$ 1.32** | $ 1.30 | **$ 1.33** | $ 1.30 |
| | | | | |
| EBITDA | **$ 187** | $ 184 | **$ 828** | $ 774 |
| EBITDA – CAD | **$ 245** | $ 241 | **$ 1,098** | $ 1,003 |

### Net Income

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

| For the<br>millions of US dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2018** | **$ 64** | **$ 294** |
| Decreased operating revenues – see Operating Revenues – Regulated Electric below | (28) | (101) |
| Decreased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below | 12 | 55 |
| Decreased OM&G expenses due to Tampa Electric's regulatory agreement to net 2018 tax reform benefits with storm costs that were recorded through OM&G in 2018. Beginning in 2019, tax reform benefits are reflected in lower base rates | 19 | 96 |
| Increased depreciation and amortization due to increased property, plant and equipment | (6) | (24) |
| Increased interest expense in support of increased capital spending | (3) | (15) |
| Decreased income tax expense quarter-over-quarter primarily due to a reduction in the Florida state corporate income tax rate. Decreased income tax expense year-over-year primarily due to a reduction in the Florida state corporate income tax rate and higher investment tax credits related to solar projects | 3 | 7 |
| Other | – | 4 |
| **Contribution to consolidated net income – 2019** | **$ 61** | **$ 316** |

Florida Electric Utility's CAD contribution to consolidated net income decreased $3 million in Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, Florida Electric Utility's CAD contribution to consolidated net income increased $38 million in 2019. Tampa Electric's contribution decreased in Q4 2019 due to unfavourable weather. Year-over-year earnings increased due to higher contribution from solar and customer growth. These increases were partially offset by higher depreciation expense and higher interest expense as the result of higher capital investments. The reduction in base rates due to tax reform was offset by lower OM&G expense in 2019, as the 2018 tax reform benefits were netted against the storm costs recorded through OM&G expense in 2018.

The impact of the change in the foreign exchange rate increased CAD earnings for the quarter and year ended December 31, 2019 by $1 million and $9 million, respectively.

### Operating Revenues – Regulated Electric

Beginning January 1, 2019, as approved by the FPSC, base rates at Tampa Electric were lowered to reflect the impact of tax reform, resulting in a $29 million decrease in revenue in Q4 2019, and approximately $103 million decrease for the year ended December 31, 2019.

Electric revenues decreased $28 million to $473 million in Q4 2019, compared to $501 million in Q4 2018. For the year ended December 31, 2019, electric revenues decreased $101 million to $1,965 million in 2019, from $2,066 million in 2018. The decreases in both periods were due to lower clause revenues and lower base rates as a result of US tax reform, partially offset by higher base revenues related to in-service of solar generation projects, and customer growth.

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

**Q4 Electric Revenues**

millions of US dollars

| | 2019 | 2018 |
|---|---|---|
| Residential | **$ 254** | $ 265 |
| Commercial | **141** | 147 |
| Industrial | **39** | 40 |
| Other (1) | **39** | 49 |
| Total | **$ 473** | $ 501 |

(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

| | 2019 | 2018 |
|---|---|---|
| Residential | **$ 1,046** | $ 1,067 |
| Commercial | **562** | 582 |
| Industrial | **156** | 161 |
| Other (1) | **201** | 256 |
| Total | **$ 1,965** | $ 2,066 |

(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")

| | 2019 | 2018 |
|---|---|---|
| Residential | **2,303** | 2,320 |
| Commercial | **1,536** | 1,568 |
| Industrial | **501** | 490 |
| Other | **579** | 514 |
| Total | **4,919** | 4,892 |

**Annual Electric Sales Volumes**

GWh

| | 2019 | 2018 |
|---|---|---|
| Residential | **9,584** | 9,418 |
| Commercial | **6,240** | 6,266 |
| Industrial | **2,021** | 2,014 |
| Other | **2,094** | 2,219 |
| Total | **19,939** | 19,917 |

### Regulated Fuel for Generation and Purchased Power

Tampa Electric is required to maintain a generating capacity greater than firm peak demand. The total Tampa Electric-owned generation capacity is 5,641 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 decreased $12 million to $143 million in Q4 2019, compared to $155 million in Q4 2018. For the year ended December 31, 2019, regulated fuel for generation and purchased power decreased $55 million to $582 million in 2019, compared to $637 million in 2018. The decrease in both periods was due to increased use of lower-cost natural gas and increased solar generation.

**Q4 Production Volumes**

GWh

| | 2019 | 2018 |
|---|---|---|
| Natural gas | **4,075** | 4,160 |
| Coal | **323** | 430 |
| Oil and petcoke | **–** | – |
| Solar | **169** | 68 |
| Purchased power | **210** | 495 |
| Total | **4,777** | 5,153 |

**Annual Production Volumes**

GWh

| | 2019 | 2018 |
|---|---|---|
| Natural gas | **17,514** | 16,097 |
| Coal | **1,214** | 3,088 |
| Oil and petcoke | **–** | 472 |
| Solar | **756** | 118 |
| Purchased power | **1,290** | 1,222 |
| Total | **20,774** | 20,997 |

**Q4 Average Fuel Costs**

US dollars

| | 2019 | 2018 |
|---|---|---|
| Dollars per Megawatt hour ("MWh") | $ 30 | $ 30 |

**Annual Average Fuel Costs**

US dollars

| | 2019 | 2018 |
|---|---|---|
| Dollars per MWh | $ 28 | $ 30 |

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.

Average fuel cost per MWh for the quarter was consistent compared to Q4 2018. Average fuel cost per MWh decreased for the year ended December 31, 2019, compared to 2018, due to increased use of lower-cost natural gas and lower-cost solar generation.

### Regulatory Recovery Mechanisms

Tampa Electric is regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC. The FPSC sets rates at a level that allows utilities such as Tampa Electric to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which occur at the initiative of Tampa Electric, the FPSC or other interested parties.

#### Other Cost Recovery

***Fuel Recovery Clause***

Tampa Electric has a fuel recovery clause approved by the FPSC, allowing 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.

## CANADIAN ELECTRIC UTILITIES

| For the<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Operating revenues – regulated electric | **$ 364** | $ 385 | **$ 1,430** | $ 1,440 |
| Regulated fuel for generation and purchased power (1) | **183** | 179 | **663** | 639 |
| Income from equity investments | **23** | 16 | **91** | 87 |
| Contribution to consolidated net income | **$ 58** | $ 44 | **$ 229** | $ 218 |
| Contribution to consolidated earnings per common share – basic | **$ 0.24** | $ 0.19 | **$ 0.95** | $ 0.94 |
| | | | | |
| EBITDA | **$ 151** | $ 140 | **$ 592** | $ 584 |

(1) Regulated fuel for generation and purchased power includes NSPI's FAM and fixed cost deferrals on the Consolidated Statements of Income, however it is excluded in the segment overview.

Canadian Electric Utilities' contribution is summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| NSPI | **$ 35** | $ 28 | **$ 138** | $ 131 |
| Equity investment in NSPML | **11** | 5 | **46** | 45 |
| Equity investment in LIL | **12** | 11 | **45** | 42 |
| **Contribution to consolidated net income** | **$ 58** | $ 44 | **$ 229** | $ 218 |

## Net Income

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

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2018** | **$ 44** | **$ 218** |
| Decreased operating revenues – see Operating Revenues – Regulated Electric below | (21) | (10) |
| Increased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below | (4) | (24) |
| Decreased FAM and fixed cost deferrals due to increased under-recovery of fuel costs which includes the impact of the Maritime Link assessment in both periods | 22 | 44 |
| Increased OM&G expenses year-over-year primarily due to higher costs for vegetation management, storm costs, variable compensation, lower administrative overhead allocated to property, plant and equipment and increased costs for information technology | 1 | (27) |
| Increased depreciation and amortization due to increased property, plant and equipment | (4) | (12) |
| Increase in income from equity investments – refer to Income from Equity Investments in NSPML and LIL below | 7 | 4 |
| Decreased other expenses, net primarily due to lower pension costs | 5 | 21 |
| Decreased income taxes primarily due to changes in tax legislation, prior year change in tax reserve, tax benefits of capital investment related to Post-Tropical Storm Dorian and decreased non-deductible pension expense partially offset by decreased tax deductions in excess of accounting depreciation related to property, plant and equipment | 5 | 18 |
| Other | 3 | (3) |
| **Contribution to consolidated net income – 2019** | **$ 58** | **$ 229** |

Canadian Electric Utilities' contribution to consolidated net income increased $14 million to $58 million in Q4 2019, compared to $44 million for the same period in 2018. This increase was a result of increased income from equity investments, decreased income taxes and lower pension costs.

For the year ended December 31, 2019 Canadian Electric Utilities' contribution to consolidated net income increased $11 million to $229 million compared to $218 million in 2018. This increase was a result of lower pension costs, decreased income taxes, higher non-fuel revenues and increased income from equity investments. This was partially offset by increased OM&G expenses and depreciation.

On September 7, 2019, Hurricane Dorian struck Nova Scotia. NSPI incurred $40 million of storm restoration costs, of which $24 million was capitalized to property, plant and equipment with the remaining $16 million charged to OM&G. There was no overall impact on NSPI earnings as NSPI's increased storm costs were offset by some of the excess non-fuel revenues that were recorded in 2019.

The timing of regulatory deferrals causes quarterly earnings volatility, while full year results are more predictable.

## NSPI

### Operating Revenues – Regulated Electric

Operating revenues decreased $21 million to $364 million in Q4 2019, compared to $385 million in Q4 2018 primarily due to decreased industrial and commercial class sales volume and decreased volume due to weather, partially offset by increased fuel related electricity pricing in 2019. For the year ended December 31, 2019, operating revenues decreased $10 million to $1,430 million compared to $1,440 million in 2018 primarily due to decreased industrial and commercial class sales volume and the impact of the Maritime Link assessment. This was partially offset by increased fuel-related electricity pricing in 2019, increased sales volume due to weather and increased residential class sales volume.

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

**Q4 Electric Revenues**

| millions of Canadian dollars | 2019 | 2018 |
|---|---|---|
| Residential | **$ 194** | $ 199 |
| Commercial | **102** | 107 |
| Industrial | **50** | 62 |
| Other | **10** | 10 |
| Total | **$ 356** | $ 378 |

**Annual Electric Revenues**

| millions of Canadian dollars | 2019 | 2018 |
|---|---|---|
| Residential | **$ 746** | $ 731 |
| Commercial | **400** | 405 |
| Industrial | **210** | 233 |
| Other | **45** | 43 |
| Total | **$ 1,401** | $ 1,412 |

**Q4 Electric Sales Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Residential | **1,210** | 1,259 |
| Commercial | **763** | 799 |
| Industrial | **571** | 669 |
| Other | **78** | 76 |
| Total | **2,622** | 2,803 |

**Annual Electric Sales Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Residential | **4,664** | 4,581 |
| Commercial | **3,068** | 3,102 |
| Industrial | **2,388** | 2,611 |
| Other | **350** | 323 |
| Total | **10,470** | 10,617 |

### Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $4 million to $183 million in Q4 2019, compared to $179 million in Q4 2018. For the year ended December 31, 2019 regulated fuel for generation and purchased power increased $24 million to $663 million compared to $639 million 2018. Changes in both periods were primarily due to increased commodity pricing and the payment of the Maritime Link assessment.

**Q4 Production Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Coal | **1,398** | 1,466 |
| Natural gas | **322** | 275 |
| Oil and petcoke | **149** | 254 |
| Purchased power – other | **139** | 175 |
| Total non-renewables | **2,008** | 2,170 |
| Wind and hydro | **306** | 318 |
| Purchased power – Independent Power Producers ("IPP") | **371** | 369 |
| Purchased power – Community Feed-in Tariff program ("COMFIT") | **163** | 153 |
| Biomass | **14** | 60 |
| Total renewables | **854** | 900 |
| Total production volumes | **2,862** | 3,070 |

**Annual Production Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Coal | **4,949** | 4,930 |
| Natural gas | **1,369** | 1,427 |
| Oil and petcoke | **981** | 1,246 |
| Purchased power – other | **786** | 540 |
| Total non-renewables | **8,085** | 8,143 |
| Wind and hydro | **1,289** | 1,202 |
| Purchased power – IPP | **1,202** | 1,275 |
| Purchased power – COMFIT | **552** | 553 |
| Biomass | **73** | 189 |
| Total renewables | **3,116** | 3,219 |
| Total production volumes | **11,201** | 11,362 |

**Q4 Average Fuel Costs**

| | | **2019** | | 2018 |
|---|---|---|---|---|
| Dollars per MWh | **$** | **64** | $ | 58 |

**Annual Average Fuel Costs**

| | | **2019** | | 2018 |
|---|---|---|---|---|
| Dollars per MWh | **$** | **59** | $ | 56 |

Average fuel cost per MWh increased in Q4 2019 and for the year ended December 31, 2019, compared to the same periods in 2018, primarily due to increased commodity pricing, timing of the payments of the Maritime Link assessment and generation mix.

NSPI's FAM regulatory liability balance decreased $46 million from $161 million at December 31, 2018 to $115 million at December 31, 2019, primarily due to under-recovery of current period fuel costs and a refund to customers of the 2018 Maritime Link assessment. This was partially offset by the recovery of the Maritime Link assessment in 2019 to be returned to customers as part of the assessment decision, demand side management costs to be returned to customers in subsequent years and interest on the FAM balance.

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place.

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. Generation mix may also be affected by plant outages, availability of renewable generation, plant performance and compliance with environmental standards and regulations.

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.

## ENL

### Income from Equity Investments in NSPML and LIL

Income from equity investments increased $7 million to $23 million in Q4 2019 compared to the same period in 2018. Income from equity investments increased $4 million to $91 million for the year ended December 31, 2019 compared to 2018. Increased income from NSPML in both periods was due to timing of revenue and operational costs and increased income from LIL, due to higher equity investment. In Q1 2018, NSPML began recording cash earnings and collecting UARB approved cash payments from NSPI.

## Regulatory Recovery Mechanisms

### 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 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 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.

On December 6, 2019, the UARB approved NSPI's three-year fuel stability plan which will result in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. For the years 2020 to 2022, differences between actual fuel costs and fuel revenues recovered from customers will be recovered from or returned to customers after 2022.

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 operated under a Rate Stability Plan for fuel costs for 2017 through 2019 which included an average overall annual rate increase of 1.5 per cent to recover fuel costs for each of these three years.

## OTHER ELECTRIC UTILITIES

All amounts are reported in USD, unless otherwise stated.

On March 25, 2019, Emera announced the sale of Emera Maine. The transaction is expected to close in early 2020, subject to MPUC approval. The Company will continue to record depreciation on these assets, through the transaction closing date, as the depreciation continues to be reflected in customer rates, and will be reflected in the carryover basis of the assets when sold. Refer to the "Developments" section for further details.

| For the<br>millions of US dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Operating revenues – regulated electric | **$ 140** | $ 140 | **$ 561** | $ 574 |
| Regulated fuel for generation and purchased power [1] | **58** | 55 | **216** | 225 |
| Adjusted contribution to consolidated net income | **$ 10** | $ 20 | **$ 57** | $ 69 |
| Adjusted contribution to consolidated net income – CAD | **$ 14** | $ 25 | **$ 76** | $ 89 |
| GBPC impairment charge | **(26)** | – | **(26)** | – |
| After-tax equity securities mark-to-market gain (loss) | **–** | (2) | **2** | (3) |
| Contribution to consolidated net income | **$ (16)** | $ 18 | **$ 33** | $ 66 |
| Contribution to consolidated net income – CAD | **$ (19)** | $ 23 | **$ 45** | $ 85 |
| Adjusted contribution to consolidated earnings per common share – basic – CAD | **$ 0.06** | $ 0.11 | **$ 0.32** | $ 0.38 |
| Contribution to consolidated earnings per common share – basic – CAD | **$ (0.08)** | $ 0.10 | **$ 0.19** | $ 0.36 |
| Net income weighted average foreign exchange rate – CAD/USD | **$ 1.32** | $ 1.32 | **$ 1.33** | $ 1.30 |
| Adjusted EBITDA | **$ 38** | $ 47 | **$ 187** | $ 200 |
| Adjusted EBITDA – CAD | **$ 52** | $ 63 | **$ 249** | $ 260 |

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

### GBPC Impairment Charge

As a result of the damage caused by Hurricane Dorian, the Company completed an asset and goodwill impairment analysis in Q4 2019 and recognized a non-cash impairment charge of $26 million USD due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. Refer to the "Developments" section and note 21 to the consolidated financial statements for the year ended December 31, 2019 for further details.

Other Electric Utilities' adjusted contribution is summarized in the following table:

| For the<br>millions of US dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Emera Maine | **$ 7** | $ 9 | **$ 35** | $ 34 |
| ECI | **3** | 11 | **22** | 35 |
| **Adjusted contribution to consolidated net income** | **$ 10** | $ 20 | **$ 57** | $ 69 |

## Net Income

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

| For the<br>millions of US dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2018** | **$ 18** | **$ 66** |
| Operating revenues – see Operating Revenues – Regulated Electric below (1) | 5 | (2) |
| Regulated fuel for generation – see Regulated Fuel for Generation and Purchased Power below (1) | (5) | 4 |
| Decreased earnings at GBPC due to Hurricane Dorian | (5) | (11) |
| GBPC impairment charge | (26) | (26) |
| Other (1) | (3) | 2 |
| **Contribution to consolidated net income – 2019** | **$ (16)** | **$ 33** |

(1) Excludes the impact of Hurricane Dorian at GBPC.

Excluding the change in mark-to-market and the GBPC impairment charge, Other Electric Utilities CAD's contribution to consolidated net income decreased $11 million in Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, the CAD contribution decreased $13 million compared to 2018. ECI's contribution decreased in both periods mainly due to lower earnings in GBPC as a result of the impact of Hurricane Dorian in Q3 2019. For the year ended December 31, 2019 compared to 2018, this was partially offset by higher sales volumes at Domlec due to the completion of hurricane restoration in 2018. Emera Maine's contribution decreased in Q4 2019 due to an unfavourable transmission revenue adjustment. Emera Maine's contribution increased for the year ended December 31, 2019 compared to 2018 due to increased capitalized construction overheads.

The foreign exchange rate had minimal impact for the three months ended December 31, 2019 and increased adjusted CAD earnings by $2 million for the year ended December 31, 2019.

## Operating Revenues – Regulated Electric

Operating revenues were consistent in Q4 2019 compared to Q4 2018. Lower sales at GBPC as a result of the impact of Hurricane Dorian were offset by increased sales volumes at Domlec and increased fuel revenue at ECI due to higher oil prices. For the year ended December 31, 2019, revenues decreased $13 million to $561 million compared to $574 million in 2018 due to lower sales at GBPC as a result of the impact of Hurricane Dorian and at Emera Maine there were lower stranded cost rates, unfavourable transmission revenue adjustments and lower transmission pool revenue as a result of lower rates.

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

**Q4 Electric Revenues**

| millions of USD | 2019 | 2018 |
|---|---|---|
| Residential | **$ 54** | $ 52 |
| Commercial | **63** | 68 |
| Industrial | **8** | 9 |
| Other (1) | **15** | 11 |
| Total | **$ 140** | $ 140 |

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

**Annual Electric Revenues**

| millions of USD | 2019 | 2018 |
|---|---|---|
| Residential | **$ 207** | $ 202 |
| Commercial | **256** | 270 |
| Industrial | **33** | 35 |
| Other (1) | **65** | 67 |
| Total | **$ 561** | $ 574 |

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

**Q4 Electric Sales Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Residential | **329** | 331 |
| Commercial | **376** | 378 |
| Industrial | **120** | 110 |
| Other | **7** | 7 |
| Total | **832** | 826 |

**Annual Electric Sales Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Residential | **1,280** | 1,273 |
| Commercial | **1,492** | 1,517 |
| Industrial | **464** | 438 |
| Other | **26** | 27 |
| Total | **3,262** | 3,255 |

## Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $3 million to $58 million in Q4 2019, compared to $55 million in Q4 2018 due to higher oil prices at ECI, partially offset by lower generation at GBPC as a result of Hurricane Dorian. For the year ended December 31, 2019, regulated fuel for generation and purchased power decreased $9 million to $216 million compared to $225 million in 2018 due to lower generation at GBPC as a result of Hurricane Dorian and the expiration of a major purchased power contract at Emera Maine, partially offset by increased volumes at Domlec.

**Q4 Production Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Oil | **332** | 335 |
| Hydro | **6** | 7 |
| Solar | **4** | 5 |
| Purchased Power | **9** | 7 |
| Total | **351** | 354 |

**Annual Production Volumes**

| GWh | 2019 | 2018 |
|---|---|---|
| Oil | **1,338** | 1,330 |
| Hydro | **20** | 24 |
| Solar | **19** | 18 |
| Purchased Power | **34** | 26 |
| Total | **1,411** | 1,398 |

**Q4 Average Fuel Costs**

| US dollars | 2019 | 2018 |
|---|---|---|
| Dollars per MWh | **$ 135** | $ 127 |

**Annual Average Fuel Costs**

| US dollars | 2019 | 2018 |
|---|---|---|
| Dollars per MWh | **$ 125** | $ 131 |

(1) Production volumes and average fuel costs relate to ECI only.

Average fuel cost per MWh increased in Q4 2019 compared to Q4 2018 due to higher oil prices at ECI and decreased for the year ended December 31, 2019 compared to 2018 due to lower average oil prices at ECI.

## Regulatory Recovery Mechanisms

### 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 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 industry restructuring 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 toward the total cost of ISO New England pool transmission facilities on a ratable basis according to the proportion of total New England load that its customers represent.

### BLPC

BLPC is regulated by the Fair Trading Commission, an independent regulator. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's fuel costs flow through a fuel pass-through mechanism which provides 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 is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. 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.

GBPC maintains insurance for its generation facilities. As with most utilities, its transmission and distribution networks are self-insured. It is currently estimated that Hurricane Dorian restoration costs for GBPC self-insured assets will be approximately $15 million USD. In January 2020, the GBPA approved the recovery of these costs through rates over a five-year period. Approximately $12 million USD of these estimated costs were incurred in 2019, and recorded as a regulatory asset.

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 the all-in rate for electricity (fuel and base rates) would be held at 2016 levels over the five-year period from 2017 through 2021. 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 7.44 per cent return on rate base and 50 per cent of amounts above 9.44 per cent return on rate base respectively.

### Domlec

Domlec is regulated by the Independent Regulatory Commission, Dominica. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. Substantially all of Domlec fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover prudently incurred fuel costs from customers in a timely manner.

## GAS UTILITIES AND INFRASTRUCTURE

All amounts are reported in USD, unless otherwise stated.

| For the<br>millions of US dollars (except per share amounts) | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| Operating revenues – regulated gas [(1)] | **$ 228** | $ 233 | **$ 832** | $ 835 |
| Operating revenues – non-regulated | **3** | 3 | **12** | 13 |
| Total operating revenue | **$ 231** | $ 236 | **$ 844** | $ 848 |
| Regulated cost of natural gas | **76** | 91 | **264** | 300 |
| Income from equity investments | **3** | 4 | **17** | 17 |
| Adjusted contribution to consolidated net income | **37** | 35 | **139** | 107 |
| Adjusted contribution to consolidated net income – CAD | **51** | 43 | **183** | 136 |
| After-tax derivative mark-to-market gain | **–** | (1) | **–** | (1) |
| Contribution to consolidated net income | **$ 37** | $ 34 | **$ 139** | $ 106 |
| Contribution to consolidated net income – CAD | **$ 51** | $ 42 | **$ 183** | $ 135 |
| Adjusted contribution to consolidated earnings per common share – basic – CAD | **$ 0.21** | $ 0.18 | **$ 0.76** | $ 0.58 |
| Contribution to consolidated earnings per common share – basic – CAD | **$ 0.21** | $ 0.18 | **$ 0.76** | $ 0.58 |
| Net income weighted average foreign exchange rate – CAD/USD | **$ 1.32** | $ 1.31 | **$ 1.33** | $ 1.29 |
| | | | | |
| Adjusted EBITDA | **$ 84** | $ 81 | **$ 311** | $ 295 |
| Adjusted EBITDA – CAD | **$ 114** | $ 107 | **$ 413** | $ 381 |

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2018 – $13 million) for the three months ended December 31, 2019 and $45 million (2018 – $44 million) for the year ended December 31, 2019, however, it is excluded from the gas revenues analysis below.

Gas Utilities and Infrastructure's adjusted contribution is summarized in the following table:

| For the<br>millions of US dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 |
| PGS | **$ 12** | $ 11 | **$ 54** | $ 47 |
| NMGC | **15** | 10 | **46** | 20 |
| Other | **10** | 14 | **39** | 40 |
| **Contribution to adjusted consolidated net income** | **$ 37** | $ 35 | **$ 139** | $ 107 |

## Net Income

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

| For the<br>millions of US dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2018** | **$ 34** | **$ 106** |
| Decreased gas operating revenues net of recognition of tax reform benefits – see Operating Revenues – Regulated Gas below | (11) | (13) |
| Decreased cost of natural gas sold – see Regulated Cost of Natural Gas below | 15 | 36 |
| Increased OM&G expenses quarter-over-quarter due to higher operating cost at PGS. Year-over-year, OM&G expense also increased due to higher self-insurance and benefits expense in PGS and NMGC in 2019 | (5) | (13) |
| Decreased depreciation and amortization due to accelerated amortization of assets related to MGP environmental remediation costs in 2018 at PGS and reduced PGS depreciation rates in 2019 related to the settlement agreement to net amortization of the MGP environmental regulatory asset and 2018 tax reform benefits | 3 | 17 |
| Recognition of tax benefit related to change in treatment of NOL carryforwards at NMGC | – | 5 |
| Recognition of tax reform benefits, net of tax, from January 2018 through June 2019 in NMGC, of which $6 million relates to 2018 | 6 | 9 |
| Other | (5) | (8) |
| **Contribution to consolidated net income – 2019** | **$ 37** | **$ 139** |

Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $9 million compared to Q4 2018. For the year ended December 31, 2019, Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $48 million compared to 2018. Increases in both periods were due to favourable weather in New Mexico, customer growth at PGS and lower depreciation and amortization at PGS. The year-over-year increase was also due to NMGC's recognition of $19 million ($14 million USD) of tax benefits in 2019.

The foreign exchange rate had minimal impact for the three months ended December 31, 2019 and increased CAD earnings by $4 million for the year ended 2019.

## Operating Revenues – Regulated Gas

Beginning January 1, 2019, as approved by the FPSC, base rates at PGS were lowered to reflect the impact of tax reform, resulting in a $4 million USD decrease in revenue in Q4 2019 and a $12 million decrease for the year ended December 31, 2019.

Gas Utilities and Infrastructure's operating revenues decreased $5 million to $228 million in Q4 2019, compared to $233 million in Q4 2018. The decrease was the result of lower off-system sales at PGS, lower base rates at PGS reflecting the impact of tax reform and lower clause revenues in New Mexico, partially offset by customer growth in PGS.

For the year ended December 31, 2019, operating revenues decreased $3 million to $832 million, compared to $835 million in 2018. The decrease was the result of lower off-system sales and lower base rates at PGS reflecting the impact of tax reform, and lower clause-related revenue at PGS and New Mexico due to lower cost of natural gas sold partially offset by favourable weather in New Mexico, customer growth in PGS, and the NMPRC's approval of NMGC retaining tax reform benefits from January 1, 2018 to June 30, 2019.

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

**Q4 Gas Revenues**

| millions of US dollars | 2019 | 2018 |
|---|---|---|
| Residential | **$ 109** | $ 116 |
| Commercial | **63** | 60 |
| Industrial (1) | **9** | 9 |
| Other (2) | **36** | 35 |
| Total (3) | **$ 217** | $ 220 |

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $11 million of finance income from Brunswick Pipeline (2018 – $13 million).

**Annual Gas Revenues**

| millions of US dollars | 2019 | 2018 |
|---|---|---|
| Residential | **$ 379** | $ 381 |
| Commercial | **225** | 225 |
| Industrial (1) | **37** | 37 |
| Other (2) | **146** | 148 |
| Total (3) | **$ 787** | $ 791 |

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $45 million of finance income from Brunswick Pipeline (2018 – $44 million).

**Q4 Gas Volumes**

| Therms (millions) | 2019 | 2018 |
|---|---|---|
| Residential | **138** | 141 |
| Commercial | **225** | 214 |
| Industrial | **376** | 339 |
| Other | **88** | 72 |
| Total | **827** | 766 |

**Annual Gas Volumes**

| Therms (millions) | 2019 | 2018 |
|---|---|---|
| Residential | **413** | 389 |
| Commercial | **830** | 795 |
| Industrial | **1,482** | 1,338 |
| Other | **317** | 269 |
| Total | **3,042** | 2,791 |

## 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 decreased $15 million to $76 million in Q4 2019, compared to $91 million in Q4 2018. For the year ended December 31, 2019, regulated cost of natural gas decreased $36 million to $264 million in Q4 2019, compared to $300 million in 2018. The decrease in both periods was due to lower commodity costs in PGS and New Mexico and lower PGS off-system sales volume.

Gas sales by type are summarized in the following table:

**Q4 Gas Volumes by Type**

| Therms (millions) | 2019 | 2018 |
|---|---|---|
| System supply | **235** | 242 |
| Transportation | **592** | 524 |
| Total | **827** | 766 |

**Annual Gas Volumes by Type**

| Therms (millions) | 2019 | 2018 |
|---|---|---|
| System supply | **754** | 745 |
| Transportation | **2,288** | 2,046 |
| Total | **3,042** | 2,791 |

## Regulatory Recovery Mechanisms

### PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

*Other Cost Recovery*

#### 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 subject to 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. As part of the depreciation study settlement agreement approved by the FPSC in February 2017, the Cast Iron/Bare Steel clause was expanded to allow recovery of accelerated replacement of certain obsolete plastic pipe. PGS projects to have all cast iron and bare steel pipe removed from its system by 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

### NMGC

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to its cost of providing service, plus an appropriate return on invested capital.

*Other Cost Recovery*

#### 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 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 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.

#### Weather Normalization Mechanism

In July 2019, the NMPRC approved changes to the company's rate design to include a Weather Normalization Mechanism. This clause is designed to lower the variability of weather impacts during the annual October through April heating season. The Weather Normalization Mechanism will make customer rates and company revenue more predictable by partially removing the impact of warmer than usual or colder than usual weather. Weather-related revenue increases or decreases experienced from October to April will be adjusted annually in October of the following heating season.

## OTHER

| For the<br>millions of Canadian dollars (except per share amounts) | | Three months ended<br>December 31 | | | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|---|---|---|
| | | **2019** | | 2018 | | **2019** | | 2018 |
| Marketing and trading margin (1) (2) | **$** | **28** | $ | 42 | **$** | **31** | $ | 115 |
| Electricity and capacity sales (3) (4) | | **2** | | 132 | | **118** | | 445 |
| Other non-regulated operating revenue | | **1** | | 12 | | **31** | | 47 |
| Total operating revenues – non-regulated | **$** | **31** | $ | 186 | **$** | **180** | $ | 607 |
| Intercompany revenue (5) | | **3** | | 10 | | **20** | | 39 |
| Non-regulated fuel for generation and purchased power (4) (6) | | **2** | | 68 | | **68** | | 238 |
| Operating, maintenance and general | | **27** | | 76 | | **130** | | 206 |
| Depreciation and amortization | | **3** | | 9 | | **11** | | 49 |
| Income from equity investments | | **7** | | 10 | | **32** | | 34 |
| Interest expense, net | | **81** | | 92 | | **337** | | 363 |
| Adjusted contribution to consolidated net income (loss) | **$** | **(58)** | $ | (28) | **$** | **(286)** | $ | (153) |
| After-tax derivative mark-to-market gain (loss) | **$** | **81** | $ | 67 | **$** | **73** | $ | 44 |
| Contribution to consolidated net income (loss) | **$** | **23** | $ | 39 | **$** | **(213)** | $ | (109) |
| Adjusted contribution to consolidated earnings per common share – basic | **$** | **(0.24)** | $ | (0.12) | **$** | **(1.19)** | $ | (0.66) |
| Contribution to consolidated earnings per common share – basic | **$** | **0.09** | $ | 0.17 | **$** | **(0.89)** | $ | (0.47) |
| | | | | | | | | |
| Adjusted EBITDA | **$** | **2** | $ | 50 | **$** | **9** | $ | 198 |

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a pre-tax mark-to-market gain of $119 million in Q4 2019 (2018 – $87 million gain) and a gain of $100 million for the year ended December 31,2019 (2018 – $16 million gain).
(3) Electricity and capacity sales exclude a pre-tax mark-to-market loss of nil in Q4 2019 (2018 – $10 million gain) and a gain of $2 million for the year ended December 31, 2019 (2018 – $38 million gain).
(4) On March 29, 2019, Emera completed the sale of the NEGG facilities. Refer to the "Developments" section for further details.
(5) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.
(6) Non-regulated fuel for generation and purchased power excludes a pre-tax mark-to-market loss of $1 million in Q4 2019 (2018 – nil) and a $2 million loss or the year ended December 31, 2019 (2018 – $5 million gain).

Other's adjusted contribution is summarized in the following table:

| For the<br>millions of Canadian dollars | | Three months ended<br>December 31 | | | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|---|---|---|
| | | **2019** | | 2018 | | **2019** | | 2018 |
| Emera Energy | **$** | **18** | $ | 44 | **$** | **37** | $ | 120 |
| Corporate | | **(75)** | | (67) | | **(322)** | | (269) |
| Other | | **(1)** | | (5) | | **(1)** | | (4) |
| **Adjusted contribution to consolidated net income (loss)** | **$** | **(58)** | $ | (28) | **$** | **(286)** | $ | (153) |

### 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<br>millions of Canadian dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income (loss) – 2018** | **$ 39** | **$ (109)** |
| Decreased marketing and trading margin – see Emera Energy below | (14) | (84) |
| Impact of sale of NEGG and Bayside Power, net of tax | (21) | (43) |
| Transaction costs related to the pending sale of Emera Maine, net of tax | (1) | (7) |
| Decreased income tax recovery due to 2018 recognition of Florida state tax apportionment benefit | – | (23) |
| Decreased income tax recovery quarter-over-quarter primarily due to the impact of effective state tax rates, partially offset by increased losses before provision for income taxes. Year-over-year increased income tax recovery primarily due to increased losses before provision for income taxes partially offset by the impact of effective state tax rates | (7) | 14 |
| Corporate share of the unrecoverable loss on GBPC facilities | (6) | (15) |
| Decrease in OM&G | 11 | 10 |
| Gain on sale of property in Florida, net of tax | – | 10 |
| Increased mark-to-market gain, net of tax, quarter-over-quarter primarily due to change in existing positions on gas contracts, partially offset by higher amortization of gas transportation assets. Year-over-year increased mark-to-market gain, net of tax, due to changes in existing positions on gas contracts and a larger reversal of mark-to-market losses in 2019, compared to 2018, partially offset by higher amortization of gas transportation assets in 2019 | 14 | 29 |
| Other | 8 | 5 |
| **Contribution to consolidated net income (loss) – 2019** | **$ 23** | **$ (213)** |

Excluding the change in mark-to-market, Other's contribution to consolidated net income decreased by $30 million for Q4 2019, compared to Q4 2018. For the year ended December 31, 2019, Other's contribution to consolidated net income decreased $133 million compared to the same period in 2018. The decrease in both periods was due to lower marketing and trading margin, the impact of the sale of NEGG and Bayside Power and the corporate share of the unrecoverable loss on GBPC's facilities, offset by decreased OM&G. The year-over-year decrease also included recognition of Florida state tax apportionment benefit in 2018 partially offset by the gain on sale of property in Florida.

## Emera Energy

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. 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 Florida, 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 decreased $14 million to $28 million in Q4 2019, compared to $42 million in Q4 2018. For the year ended December 31, 2019, margin decreased $84 million to $31 million compared to $115 million in 2018. The decrease in both periods was due to less favourable market conditions, specifically lower natural gas prices and volatility and higher fixed cost commitments for gas transportation and storage assets in 2019, compared to 2018.

In March 2019, the Company completed the sale of Emera Energy's NEGG and Bayside facilities. Refer to the "Developments" section for further details.

## 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 revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in 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 has a $6.9 billion capital investment plan over the 2020-to-2022 period and the potential for additional capital opportunities of $500 million to $1 billion over the forecast period. This plan includes significant rate base investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. 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 Emera Maine sale, to support normal operations, repayment of existing debt and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Equity requirements in support of the Company's capital investment plan will predominantly be funded in the equity capital markets through the dividend reinvestment plan and the issuance of common and preferred equity. Emera has credit facilities with varying maturities that cumulatively provide $3.2 billion of credit. Refer to notes 22 and 24 in the consolidated financial statements for additional information regarding the credit facilities.

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, 2019 and 2018 include:

| millions of Canadian dollars | **2019** | 2018 | $ Change |
|---|---|---|---|
| Cash, cash equivalents and restricted cash, beginning of period | **$ 372** | $ 503 | $ (131) |
| **Provided by (used in):** | | | |
| Operating cash flow before changes in working capital | **1,598** | 1,806 | (208) |
| Change in working capital | **(73)** | (116) | 43 |
| Operating activities | **1,525** | 1,690 | (165) |
| Investing activities | **(1,617)** | (2,190) | 573 |
| Financing activities | **14** | 344 | (330) |
| Effect of exchange rate changes on cash and cash equivalents | **(20)** | 25 | (45) |
| Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period | **$ 274** | $ 372 | $ (98) |

### Cash Flow from Operating Activities

Net cash provided by operating activities decreased $165 million to $1,525 million for the year ended December 31, 2019, compared to $1,690 million for the same period in 2018.

Cash from operations before changes in working capital decreased $208 million in 2019. The decrease was due to lower marketing and trading margin at EES and lower earnings from Emera Energy Generation as a result of the sale of NEGG. These were partially offset by higher revenue collected for the in-service of solar generation projects and lower under-recovery from customers on clause related costs at Tampa Electric.

Changes in working capital increased operating cash flows by $43 million. The increase was due to a refund of $146 million ($109 million USD) of alternative minimum tax credit carryforwards in April 2019. This was partially offset by unfavourable changes in cash collateral at NSPI and increased investment in fuel inventory at NSPI.

### Cash Flow Used in Investing Activities

Net cash used in investing activities decreased $573 million to $1,617 million for the year ended December 31, 2019, compared to $2,190 million in 2018. In 2019, Emera received proceeds of $875 million on dispositions, primarily from the sale of the NEGG and Bayside facilities. These proceeds were partially offset by an increase in capital expenditures.

Capital expenditures for the year ended December 31, 2019, including AFUDC, were $2,516 million compared to $2,178 million in 2018. Details of the 2019 capital spend by segment are shown below:

- $1,414 million – Florida Electric Utility (2018 – $1,235 million);
- $389 million – Canadian Electric Utilities (2018 – $350 million);
- $200 million – Other Electric Utilities (2018 – $190 million);
- $450 million – Gas Utilities and Infrastructure (2018 – $332 million); and
- $63 million – Other (2018 – $71 million).

### Cash Flow from Financing Activities

Net cash provided by financing activities decreased $330 million to $14 million for the year ended December 31, 2019, compared to $344 million for the same period in 2018. The decrease was due to repayment of corporate long-term debt, repayments at NSPI, a 2018 preferred share issuance and net repayment of committed credit facilities at NMGC. These were partially offset by proceeds from Emera's non-revolving credit facilities, issuance of long-term debt at NSPI and NMGC in 2019, the 2018 repayment of debt at TECO Finance, net borrowings from credit facilities by TEC and proceeds from Emera's ATM program.

## WORKING CAPITAL

As at December 31, 2019, Emera's cash and cash equivalents were $222 million (2018 – $316 million) and Emera's investment in non-cash working capital was $566 million (2018 – $449 million). Of the cash and cash equivalents held at December 31, 2019, $208 million was held by Emera's foreign subsidiaries (2018 – $280 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, 2019, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

| millions of Canadian dollars | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Long-term debt principal (1) | $ 550 | $ 1,665 | $ 512 | $ 831 | $ 987 | $ 10,261 | $ 14,806 |
| Interest payment obligations (2) (3) | 667 | 621 | 583 | 558 | 536 | 7,039 | 10,004 |
| Purchased power (4) (5) | 210 | 233 | 237 | 246 | 249 | 2,228 | 3,403 |
| Transportation (6) | 514 | 398 | 340 | 281 | 264 | 2,720 | 4,517 |
| Pension and post-retirement obligations (7) (8) | 32 | 37 | 33 | 32 | 99 | 306 | 539 |
| Capital projects (9) | 411 | 109 | 103 | 86 | – | – | 709 |
| Fuel, gas supply and storage | 466 | 133 | 22 | 1 | – | – | 622 |
| Asset retirement obligations | 2 | 43 | 1 | 1 | 1 | 360 | 408 |
| Long-term service agreements (10) (11) | 52 | 37 | 36 | 27 | 26 | 100 | 278 |
| Equity investment commitments (12) | 240 | – | – | – | – | – | 240 |
| Leases and other (13) | 19 | 19 | 18 | 17 | 8 | 118 | 199 |
| Demand side management | 38 | 41 | 43 | – | – | – | 122 |
| Long-term payable | 5 | 5 | 5 | 5 | – | – | 20 |
| Convertible debentures | – | – | – | – | – | 1 | 1 |
| | $ 3,206 | $ 3,341 | $ 1,933 | $ 2,085 | $ 2,170 | $ 23,133 | $ 35,868 |

As noted below, contractual obligations at December 31, 2019 include amounts related to Emera Maine. On completion of the sale of Emera Maine, all of the remaining future obligations related to these contractual commitments will be transferred to the buyer. Refer to the "Developments" section for additional information.

(1) Includes $518 million related to Emera Maine ($49 million in 2020; $107 million in 2022; $11 million in 2023 and $351 million thereafter).
(2) 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, 2019, including any expected required payment under associated swap agreements.
(3) Includes $423 million related to Emera Maine ($22 million in 2020; $21 million in 2021; $16 million in 2022; $15 million in 2023, $15 million in 2024 and $334 million thereafter).
(4) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(5) Includes $520 million related to Emera Maine ($13 million in 2020; $23 million in 2021; $27 million in 2022; $31 million in 2023; $31 million in 2024 and $395 million thereafter).
(6) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(7) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans (excluding the possibility of wind-up), plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.
(8) Includes $65 million related to Emera Maine ($3 million in 2020; $3 million in 2021; $3 million in 2022; $4 million in 2023; $4 million in 2024 and $48 million thereafter).
(9) Includes $345 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.
(10) 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.
(11) Includes $44 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($19 million in 2020; $9 million in 2021; $8 million in 2022; and $8 million in 2023).
(12) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(13) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years from its January 15, 2018 in-service date. The UARB approved payment for 2019 was $111 million, subject to a $10 million holdback and as at December 31, 2019, $101 million has been paid. The UARB approved payment for 2020 is $145 million, subject to a holdback of up to $10 million. As part of NSPI's 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and estimated amounts of $164 million and $162 million for 2021 and 2022, respectively. These estimated amounts are subject to review and approval by the UARB. The timing and amounts payable to NSPML for the remainder of the 37-year commitment period are dependent on regulatory filings with the UARB.

Emera has committed to obtain certain transmission rights for Nalcor Energy, if requested, to enable them to transmit energy which is not otherwise used in Newfoundland or Nova Scotia. This energy would be transmitted from Nova Scotia to New England energy markets beginning at first commercial power of the Muskrat Falls hydroelectric generating facility and related transmission assets when Nalcor commences delivery of the NS Block, and continuing for 50 years. As transmission rights are contracted, Emera includes the obligations within "Leases and other" in the above table.

## FORECASTED GROSS CONSOLIDATED CAPITAL EXPENDITURES

2020 forecasted gross consolidated capital expenditures are as follows:

| millions of Canadian dollars | Florida Electric Utility | Canadian Electric Utilities | Other Electric Utilities (1) | Gas Utilities and Infrastructure | Other | Total |
|---|---|---|---|---|---|---|
| Generation | $ 396 | $ 141 | $ 96 | $ – | $ 1 | $ 634 |
| New renewable generation | 412 | – | – | – | – | 412 |
| Transmission | 91 | 50 | 9 | – | – | 150 |
| Distribution | 253 | 126 | 50 | – | – | 429 |
| Gas transmission and distribution | – | – | – | 709 | – | 709 |
| Facilities, equipment, vehicles, and other | 136 | 58 | 11 | 48 | 73 | 326 |
| | $ 1,288 | $ 375 | $ 166 | $ 757 | $ 74 | $ 2,660 |

(1) Includes approximately $25 million related to Emera Maine expenditures in the first quarter only.

## DEBT MANAGEMENT

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.2 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 Inc. – Operating and acquisition credit facility | June 2024 | $ 900 | $ 497 | $ 403 |
| TECO Finance, Inc. – in USD – Operating credit facilities | March 2020 – March 2022 | 900 | 505 | 395 |
| NSPI – Operating credit facility | October 2024 | 600 | 312 | 288 |
| TEC – in USD – credit facilities (1) | March 2021 – March 2022 | 550 | 349 | 201 |
| NMGC – in USD – Operating credit facility | March 2022 | 125 | 7 | 118 |
| Emera Maine – in USD – Operating credit facility | February 2023 | 80 | 11 | 69 |
| Other – in USD – Operating credit facility | Various | 32 | 17 | 15 |

(1) This facility is available for use by Tampa Electric and PGS. At December 31, 2019, Tampa Electric had utilized $258 million USD and PGS had utilized $91 million USD of the facility.

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, 2019. Emera's significant covenant is listed below:

| | Financial Covenant | Requirement | As at December 31, 2019 |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.59 : 1 |

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

### Florida Electric Utilities

On February 6, 2020, TEC entered into a $300 million USD non-revolving credit agreement with a maturity date of February 4, 2021. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR, prime rate or the federal funds rate, plus a margin.

On December 19, 2019, TEC increased its $325 million USD revolving credit facility by $75 million USD to $400 million USD. There were no other changes in commercial terms.

On July 24, 2019, TEC completed a $300 million USD 30-year senior notes issuance. The notes bear interest at a rate of 3.625 per cent and have a maturity date of June 15, 2050.

### Canadian Electric Utilities

On November 25, 2019, NSPI amended its operating credit facility to extend the maturity from October 2023 to October 2024. All other terms of the agreement are the same.

On August 2, 2019, NSPI repaid a $95 million debenture upon maturity. The debenture was repaid using its operating credit facility.

On April 4, 2019, NSPI completed a $400 million Series AB 30-year medium term notes issuance. The notes bear interest at a rate of 3.57 per cent and have a maturity date of April 5, 2049.

### Gas Utilities and Infrastructure

On December 19, 2019, NMGC completed a $80 million USD 30-year unsecured notes issuance. The notes bear interest at a rate of 3.72 per cent and have a maturity date of December 15, 2049.

On December 19, 2019, NMGC completed a $15 million USD 15-year unsecured notes issuance. The notes bear interest at a rate of 3.24 per cent and have a maturity date of December 15, 2034.

On July 31, 2019, New Mexico Gas Intermediate ("NMGI") repaid a $50 million USD note upon maturity. The note was repaid using cash on hand.

On May 17, 2019, Emera Brunswick Pipeline amended the maturity date of its $250 million Credit Agreement from February 2022 to May 2023. There were no other material changes in commercial terms.

### Other Electric Utilities

On December 10, 2019, Emera Maine completed a securities issuance for $60 million USD senior unsecured notes. The 30-year notes bear interest at a rate of 3.79 per cent and will mature on December 10, 2049.

### Other

On December 16, 2019, Emera entered into a $400 million non-revolving credit agreement with a maturity date of December 15, 2020. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at Bankers Acceptance rates or prime rate advances, plus a margin.

On December 2, 2019, Emera's Series G $225 million 4.83 per cent medium-term notes matured and were repaid. The notes were repaid using existing credit facilities.

On June 14, 2019, Emera US Finance LP repaid a $500 million USD note upon maturity. The note was repaid using short-term investments, temporarily held from the sale of the NEGG facilities.

On June 13, 2019, Emera extended the maturity date of its $900 million revolving credit facility from June 2020 to June 2024. There were no other significant changes in commercial terms from the prior agreement.

On March 7, 2019, TECO Energy/Finance extended the maturity date of its $500 million USD credit facility from March 8, 2019 to March 5, 2020. There were no other significant changes in commercial terms from the prior agreement.

## CREDIT RATINGS

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

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

On December 19, 2019, Moody's Investor Services affirmed its Baa2 senior unsecured ratings on TECO Energy/TECO Finance and TEC's A3 senior unsecured ratings and changed its ratings outlook to positive from stable.

On November 29, 2019, DBRS Limited affirmed NSPI's A (low) issuer and issue rating with a stable trend.

On June 27, 2019, Moody's Investor Services affirmed Emera's Baa3 issuer and senior unsecured ratings and Emera US Finance LP's Baa3 guaranteed senior unsecured rating and changed its ratings outlook to stable from negative.

On June 13, 2019, Fitch Ratings assigned ratings and outlook for Emera for the first time. Emera was assigned a BBB issuer default and senior unsecured rating with stable outlook. At the same time, Fitch Ratings assigned TEC an A- issuer default rating and an A senior unsecured rating with stable outlook.

### SHARE CAPITAL

#### Emera

As at December 31, 2019, Emera had 242.48 million (2018 – 234.12 million) common shares issued and outstanding. For the year ended December 31, 2019, 8.36 million common shares were issued (2018 – 5.35 million) for net proceeds of $400 million (2018 – $215 million).

As at December 31, 2019, Emera had 41 million preferred shares issued and outstanding (2018 – 41 million).

On January 7, 2020, Emera announced it would not redeem the 8,000,000 Cumulative Rate Reset First Preferred Shares, Series F Shares. The holders of the Series F Shares have the right, at their option, to convert all or any of their Series F Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series G of the Company on February 15, 2020, or to continue to hold their Series F Shares. On February 6, 2020, Emera announced that, after having taken into account all conversion notices received from holders, no First Preferred Shares, Series F Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series G Shares.

## PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2020 for defined benefit pension plans is expected to be $44 million (2019 – $52 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 only, are $34 million for 2020, including $2 million for a full year of contribution for Emera Maine (2019 – $34 million actual). The actual contribution is expected to be lower depending on the timing of the pending sale of Emera Maine.

### DEFINED BENEFIT PENSION PLAN SUMMARY

millions of Canadian dollars — As at December 31, 2019

| Plans by region | TECO Energy Pension Plans | NSPI Pension Plans | Emera Maine Pension Plans | Caribbean Plans | Total |
|---|---|---|---|---|---|
| Assets as at December 31, 2019 | $ 1,034 | $ 1,357 | $ 192 | $ 10 | $ 2,593 |
| Accounting obligation at December 31, 2019 | 1,094 | 1,491 | 222 | 15 | 2,822 |
| Accounting expense during fiscal 2019 | $ 19 | $ 16 | $ 2 | $ 1 | $ 38 |

## 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, 2019 totalled $740 million (2018 – $759 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 guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2019:

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 $82 million USD (December 31, 2018 – $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 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 2020 and is renewed annually. The amount committed as at December 31, 2019 was $52 million (December 31, 2018 – $49 million).

## DIVIDEND PAYOUT RATIO

Emera has provided annual dividend growth guidance of four to five per cent through 2022. 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 2019 were $2.3750 ($0.5875 in Q1, Q2, and Q3 and $0.6125 in Q4) per common share and $2.2825 ($0.5650 in Q1, Q2, and Q3 and $0.5875 in Q4) per common share for 2018, representing a payout ratio of 91 per cent of adjusted net income in 2019 and 79 per cent in 2018.

On September 27, 2019, Emera's Board of Directors approved an increase in the annual common share dividend rate from $2.35 to $2.45. The first quarterly dividend payment at the increased rate was paid on November 15, 2019.

## 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 $107 million for the year ended December 31, 2019 (2018 – $97 million). 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 – Canadian Electric Utilities – 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 $63 million for the year ended December 31, 2019 (2018 – $29 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, 2019 and at December 31, 2018.

## 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. The commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by changes in government and shifts in government policy. This includes initiatives regarding deregulation or restructuring of the energy industry, which could occur as a result of climate change concerns. Emera also holds 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. A proposed constitutional initiative relating to electric utilities in Florida was rejected by the Florida Supreme Court as misleading and will not be included on ballots for the November 2020 election. The proposed amendment to the Florida Constitution would have limited the business of investor-owned utilities to construction, operation and repair of electrical transmission and distribution systems. It would have also granted customers of investor-owned utilities the right to generate electricity and to choose their electricity provider.

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

### GLOBAL CLIMATE CHANGE RISK

The Company is subject to risks that arise or may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon emissions. City, state, provincial and federal governments have been setting policies and enacting laws and regulations to deal with climate change impacts in a variety of ways, including de-carbonization initiatives and promotion of cleaner energy and renewable energy generation of electricity. Refer to "Changes in Environmental Legislation". Insurance companies have begun to limit their exposure to coal-fired electricity generation, and are evaluating the medium and long-term impacts of climate change which may result in fewer insurers, more restrictive coverage and increased premiums. Refer to the "Markets" section below and "Uninsured Risk".

Climate change may lead to increased frequency and intensity of weather events and related impacts such as storms, ice storms, hurricanes, cyclones, heavy rainfall, extreme winds, wildfires, flooding and storm surge. The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce even greater damage to coastal generation and other facilities. Climate change is also characterized by rising global temperatures. Increased air temperatures may bring increased frequency and severity of wildfires within the Company's service territories. Refer to "Weather Risk" and "System Operating and Maintenance Risks".

In response, the Company has made significant investments to facilitate the use of renewable and lower-carbon energy including wind generation, the Maritime Link in Atlantic Canada, and solar generation and the modernization of the Big Bend Power Station in Florida. Since 2005, NSPI has reduced carbon emissions by 35 per cent, exceeding the 2030 reduction target of 30 per cent set at the COP 21 Climate Conference, and expects to achieve a greater-than 50 per cent reduction by 2030; nearly double the Government of Canada's target set under the Paris Agreement. NSPI is on track to meet a provincially-mandated target of 40 per cent renewable generation by 2020. Within Emera's natural gas utilities, there are ongoing efforts to reduce methane and carbon emissions through replacement of aging infrastructure, more efficient operations, operational and supply chain optimization and support of public policy initiatives that address the effects of climate change.

The Company's long-term capital investment plan includes significant investment across the portfolio in renewable and cleaner generation, infrastructure modernization, storm hardening, energy storage and customer-focused technologies. All of these initiatives contribute toward mitigating the potential impacts of climate change. The Company continues to engage with government, regulators, industry partners and stakeholders to share information and participate in the development of climate change related policies and initiatives.

### Physical Impacts

The Company is subject to physical risks that arise, or may arise, from global climate change, including damage to operating assets from more frequent and intense weather events and from wildfires due to warming air temperatures and increasing drought conditions. Substantially all of the Company's fossil fueled generation assets are located at coastal, or near coastal, sites and as such are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding. Refer to "Weather Risk".

These risks are mitigated to an extent through features such as flood walls at certain plants and through the location of other plants on higher ground. Planned investments in under-grounding parts of the electricity infrastructure also contributes to risk mitigation as does insurance coverage (for assets other than electricity transmission and distribution assets) and regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts to smooth out the recovered costs of storm restoration over time.

### Reputation

Failure to address issues related to climate change could affect Emera's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital. Refer to "Liquidity and Capital Market Risk". The Company seeks to mitigate this in part by moving away from higher-carbon generation in favour of lower-carbon generation and non-emitting renewable generation.

### Markets

Changing carbon-related costs, policy and regulatory changes and shifts in supply and demand factors could lead to more expensive or more scarce products and services that are required by the Company in its operations. This could lead to supply shortages and delivery delays as well as the need to source alternate products and services. The Company seeks to mitigate these risks through close monitoring of such developments and adaptive changes to supply chain procurement strategies.

Given concerns regarding carbon-emitting generation, those assets and businesses may, over time, become difficult (or uneconomic) to insure in commercial insurance markets. In the short term this may be mitigated through increased investment in engineered protection or alternative risk financing (such as funded self-insurance or regulatory structures, including storm reserves). Longer-term mitigation may be achieved through infrastructure siting decisions and further engineered protections. This risk is also mitigated through the continued transition away from high-carbon generation sources to sources with low or zero carbon emissions.

### Policy

Government and regulatory initiatives, including greenhouse gas emissions standards, air emissions standards and generation mix standards, are being proposed and adopted in many jurisdictions in response to concerns regarding the effects of climate change. In some jurisdictions, government policy has included timelines for mandated shutdowns of coal generating facilities, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and longer terms, this could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

The Company is committed to compliance with all climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance over time. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation". The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, other stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition over time to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent.

### Regulatory

Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets. Valuation impairments could result from such regulatory outcomes. Mitigation efforts in respect of these risks include active engagement with policy makers and regulators to find mechanisms to avoid such impacts while being responsive to customers' and stakeholders' objectives.

### Legal

The Company could, in the future, face litigation or regulatory action related to environmental harms from carbon emissions or climate change public disclosure issues. The Company addresses these risks through compliance with all relevant laws, emissions reduction strategies and public disclosure of climate change risks.

### Water Resources

For thermal plants requiring cooling water, reduced availability of water resulting from climate change could adversely impact operations or the costs of operations. The Company seeks ways to reduce and recycle water as it does in its Polk power plant in Florida, where recovered and treated wastewater is used in operations to reduce reliance on fresh water supplies in an area where water is not as abundant as in other markets.

The Company operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and ambient air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities. The Company is reinvesting in the efficiency of certain of such facilities to increase generation capacity and continues to monitor changing hydrology patterns. Such issues may also affect the availability of third party-owned hydroelectricity purchased power sources.

## WEATHER RISK

The Company is subject to risks that arise or may arise from weather including seasonal variations impacting energy sales, more frequent and intense weather events, changing air temperatures, wildfires and extreme weather conditions associated with climate change. Refer to "Global Climate Change Risk".

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. Further, extreme weather conditions such as hurricanes and other severe weather conditions associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could have an effect on the Company's results of operations, financial conditions or cash flows.

Extreme weather events create a risk of physical damage to the Company's assets. High winds can impact 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 hydroelectric 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 typically 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.

The 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.

In 2019, NSPI completed registration under the Nova Scotia Cap-and-Trade Program Regulations. This provincial carbon pricing program meets the benchmark set by the Government of Canada. In the United States, in June 2019, the Environmental Protection Agency issued the final Affordable Clean Energy ("ACE") rule. The ACE rule establishes GHG emission guidelines for states to regulate GHG emissions from existing coal-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.

Legislative or regulatory changes could influence decisions regarding early retirement of generation facilities and may result in stranded costs if the Company is not able to fully recover the costs and investment in the affected generation assets. Recovery is not assured and is subject to prudency review. In addition, these changes may curtail sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses. 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 in compliance 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, periodic security testing, 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 may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. 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, and on net income earned outside of Canada. 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 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, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. 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 processes, 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.

## COUNTERPARTY RISK

Emera is exposed to risk related to its reliance on certain key partners, suppliers and customers. Emera is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty's non-performance under an agreement. Emera manages this counterparty risk by monitoring significant developments with its customers, partners and suppliers. The Company also manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments may be conducted on new customers and counterparties, and deposits or collateral are requested on accounts as required.

## COUNTRY RISK

Earnings outside of Canada constituted 61 per cent (all from the US) of Emera's earnings in 2019 (2018 – 69 per cent, with 65 per cent from the US and 4 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, including climate change, 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.

## 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 IT asset lifecycle planning and management, governance, internal auditing and testing of systems, and executive oversight. Employees with extensive subject matter expertise assist in risk identification and mitigation, project management, implementation and training. System resiliency, formal disaster recovery and backup processes, combined with critical incident response practices, ensure that continuity is maintained in the event of any disruptions.

## 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, solar panels 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. Refer to "Global Climate Change Risk" and "Weather Risk". 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's operations have significant capital projects that may require approvals and permits at the federal, provincial, state, regional and local level. There can be no assurance that Emera will be able to obtain the necessary project approvals or applicable permits. 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. Certain facilities, in particular coal and other thermal generation, may, over time, become more difficult (or uneconomic) to insure as a result of the impact of global climate change. Refer to "Global Climate Change Risk – Markets". 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 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. 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 NSPI, NMGC and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled 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. Tampa Electric and PGS have no derivatives related to hedging as a result of a Florida Public Service Commission approved five-year moratorium on hedging of natural gas purchases which ends on December 31, 2022.

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<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Derivative instrument liabilities (current and long-term liabilities) | **$ (1)** | $ (5) |
| Net derivative instrument liabilities | **$ (1)** | $ (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<br>millions of Canadian dollars | Year ended December 31 | |
|---|---|---|
| | **2019** | 2018 |
| Operating revenues – regulated | **$ (3)** | $ 5 |
| Non-regulated fuel for generation and purchased power | **–** | 1 |
| Effective net gains (losses) | **$ (3)** | $ 6 |

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<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$ 28** | $ 104 |
| Regulatory assets (current and other assets) | **80** | 6 |
| Derivative instrument liabilities (current and long-term liabilities) | **(78)** | (6) |
| Regulatory liabilities (current and long-term liabilities) | **(42)** | (115) |
| Net asset (liability) | **$ (12)** | $ (11) |

## REGULATORY IMPACT RECOGNIZED IN NET INCOME

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

| For the<br>millions of Canadian dollars | Year ended December 31 | |
|---|---|---|
| | **2019** | 2018 |
| Regulated fuel for generation and purchased power (1) | **$ 5** | $ 11 |
| Net gains | **$ 5** | $ 11 |

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

### HFT ITEMS RECOGNIZED ON THE BALANCE SHEETS

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

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$ 58** | $ 62 |
| Derivative instrument liabilities (current and long-term liabilities) | **(291)** | (354) |
| Net derivative instrument assets (liability) | **$ (233)** | $ (292) |

### 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<br>millions of Canadian dollars | | Year ended December 31 |
|---|---|---|
| | **2019** | 2018 |
| Non-regulated operating revenues | **$ 282** | $ 193 |
| Non-regulated fuel for generation and purchased power | **(6)** | 2 |
| Other income (expenses), net | **–** | – |
| Net gains (losses) | **$ 276** | $ 195 |

### OTHER DERIVATIVES RECOGNIZED ON THE BALANCE SHEETS

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

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$ 1** | $ 1 |
| Net derivative instrument assets (liabilities) | **$ 1** | $ 1 |

### OTHER DERIVATIVES RECOGNIZED IN NET INCOME

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

| For the<br>millions of Canadian dollars | | Year ended December 31 |
|---|---|---|
| | **2019** | 2018 |
| Operating, maintenance and general | **$ 28** | $ – |
| Interest expense, net | **–** | (1) |
| Net gains (losses) | **$ 28** | $ (1) |

## 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, 2019 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, 2019, 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 $1,552 million (2018 – $1,569 million) of regulatory assets and $2,181 million (2018 – $2,610 million) of regulatory liabilities as at December 31, 2019.

### 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 $891 million at December 31, 2019 (2018 – $955 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 9.5 years (7.5 years for 2019 benefit cost) 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:

| | | **2019** | | 2018 |
|---|---|---|---|---|
| | **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 | **4.34% / 3.13%** | **7.35% / 7.00%** | 3.63% | 6.85% |
| TECO Energy Group Supplemental Executive Retirement Plan (1) | **4.02%** | **N/A** | 3.11% / 3.84% | N/A |
| TECO Energy Group Benefit Restoration Plan (1) | **4.12% / 3.94% / 3.32%** | **N/A** | 3.26% / 3.76% / 4.01% | N/A |
| TECO Energy Post-retirement Health and Welfare Plan | **4.38%** | **N/A** | 3.70% | N/A |
| New Mexico Gas Company Retiree Medical Plan | **4.39%** | **3.25%** | 3.71% | 4.00% |
| NSPI | **3.83%** | **6.00%** | 3.50% | 6.00% |
| Bangor Hydro (2) | **4.19%** | **6.35%** | 3.53% | 6.55% |
| Maine Public Service (2) | **4.12%** | **6.55%** | 3.45% | 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 and expected return on assets 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 $84 million in 2019 (2018 – $115 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 2019 benefit cost of $9 million and $6 respectively (2018 – $9 million and $6 million).

## UNBILLED REVENUE

Electric and gas 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, 2019, unbilled revenues totalled $265 million (2018 – $296 million) on total annual operating revenues of $6,111 million (2018 – $6,524 million).

## PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 57 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.

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. 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 expense was $881 million for the year ended December 31, 2019 (2018 – $881 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, 2019, the Company had goodwill with a total carrying amount of $5,835 million (December 31, 2018 – $6,313 million). This goodwill represents the excess of the acquisition purchase price for TECO Energy (Tampa Electric, PGS and NMGC reporting units) and GBPC over the fair values assigned to individual assets acquired and liabilities assumed. The change in the carrying value from 2019 to 2018 was a result of the held for sale classification of Emera Maine, recognition of the GBPC impairment charge and the strengthening US dollar on the goodwill balances.

In Q4 2019, the Company performed quantitative impairment assessments at the reporting unit level. The quantitative assessments for Tampa Electric, PGS and NMGC concluded that the fair value of the reporting units exceeded their respective carrying amounts. However, it was determined that including the impact of Hurricane Dorian, the fair value of GBPC did not exceed its carrying amount. As a result of this assessment, a goodwill impairment charge of $30 million was recorded in 2019, leaving goodwill of $70 million related to GBPC as at December 31, 2019. No impairment was recorded in 2018. Refer to note 21 to the consolidated financial statements for further details.

Emera Maine's assets and liabilities are classified as held for sale, including $148 million of goodwill, and are 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 goodwill was not impaired.

The fair market value of reporting units 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 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.

## 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 a triggering event occurs, such as a significant market disruption or sale of a business. 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 as the estimates are highly susceptible to change and the impact of an impairment on reported assets and earnings could be material. Management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and the current and expected market conditions in such periods. Markets can experience significant uncertainties. Estimates based on 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.

In Q4 2019, due to the damage incurred from Hurricane Dorian, the Company determined that the undiscounted expected future cash flows for GBPC's property, plant and equipment did not exceed its carrying amount. As a result of this assessment, a non-cash impairment charge of $18 million USD was recorded in 2019 based on the excess of the carrying amount of the property, plant and equipment over its estimated fair value. The charge was recorded as a regulatory asset as management anticipates that recovery of these prudently incurred costs through insurance or a regulatory process is probable. GBPC recorded an offsetting insurance receivable of $15 million USD against this regulatory asset. It is anticipated that the regulatory asset balance of $3 million USD remaining at December 31, 2019 will be recovered through insurance. No impairment was recorded in 2018.

## 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 examinations of the Company's tax returns.

The Company believes the accounting estimate related to income taxes is a critical estimate for several reasons. The realization of deferred tax assets is dependent upon the generation of sufficient taxable income, both operating and capital, in future periods. A change in the estimated valuation allowance could have a material impact on reported assets and results of operations. 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 the Company's estimate of income taxes, including the potential for elimination or reduction of our ability to realize tax benefits and to utilize deferred tax assets.

## ASSET RETIREMENT OBLIGATIONS ("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, 2019, the AROs recorded on the balance sheet were $185 million (2018 – $205 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $422 million (2018 – $451 million), which will be incurred between 2019 and 2061. The majority of these costs will be incurred between 2028 and 2050.

### CAPITALIZED OVERHEAD

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, 2019, $199 million of overhead costs (2018 – $187 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 observable 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 have contract terms that 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 2019, are described as follows:

### LEASES

On January 1, 2019, the Company adopted Accounting Standard Updates ("ASU") 2016-02, *Leases (Topic 842)*, including all related amendments, using the modified retrospective approach. The standard requires lessees to recognize leases on the balance sheet for all leases with a term of longer than twelve months and disclose key information about leasing arrangements.

As permitted by the optional transition method, Emera did not restate comparative financial information in the Company's consolidated financial statements, did not reassess whether any expired or existing contracts contained leases and carried forward existing lease classifications. Additionally, the Company elected to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under the leasing guidance within ASC Topic 840. The Company elected to use hindsight to determine the lease term for existing leases and elected to not separate lease components from non-lease components for all lessee and lessor arrangements.

Emera has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There were no updates to information technology systems as a result of implementation.

The Company's adoption of this new standard resulted in right-of-use ("ROU") assets and lease liabilities of approximately $58 million as of January 1, 2019. The ROU assets and lease liabilities were measured at the present value of remaining lease payments using the Company's incremental borrowing rate.

There was no impact to opening retained earnings as at January 1, 2019 or the Company's net income or cash flows for the year ended December 31, 2019 as a result of the adoption of the standard. There were no significant impacts to Emera's accounting for lessor arrangements. Refer to note 18 of the consolidated financial statements for further detail.

### TARGETED IMPROVEMENTS TO ACCOUNTING FOR HEDGING ACTIVITIES

On January 1, 2019, the Company adopted 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. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

### CLOUD COMPUTING

In August 2018, the Financial Accounting Standards Board ("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 is 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 early adopted the standard effective January 1, 2019 and elected to apply the guidance prospectively. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

## 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.

### 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. The Company adopted ASU 2016-13 effective January 1, 2020, with no significant changes to accounting and disclosure identified related to the adoption of the standard.

### SIMPLIFYING THE ACCOUNTING FOR INCOME TAXES

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes*. The standard simplifies the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740 related to the approach for intraperiod tax allocation, simplifies aspects of accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard will be applied on both a prospective and retrospective basis. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

## SUMMARY OF QUARTERLY RESULTS

| For the quarter ended<br>millions of Canadian dollars<br>(except per share amounts) | Q4<br>2019 | Q3<br>2019 | Q2<br>2019 | Q1<br>2019 | Q4<br>2018 | Q3<br>2018 | Q2<br>2018 | Q1<br>2018 |
|---|---|---|---|---|---|---|---|---|
| Operating revenues | **$ 1,616** | **$ 1,299** | **$ 1,378** | **$ 1,818** | $ 1,799 | $ 1,495 | $ 1,423 | $ 1,807 |
| Net income attributable to common shareholders | **193** | **55** | **103** | **312** | 231 | 118 | 90 | 271 |
| Adjusted net income attributable to common shareholders | **145** | **122** | **130** | **224** | 167 | 191 | 111 | 202 |
| Earnings per common share – basic | **0.79** | **0.23** | **0.43** | **1.32** | 0.98 | 0.51 | 0.38 | 1.17 |
| Earnings per common share – diluted | **0.80** | **0.23** | **0.43** | **1.32** | 0.98 | 0.50 | 0.38 | 1.17 |
| Adjusted earnings per common share – basic | **0.60** | **0.51** | **0.54** | **0.95** | 0.71 | 0.82 | 0.48 | 0.87 |

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.

# 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 14, 2020

**"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, 2019 and 2018, 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, 2019 and 2018, 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.

The engagement partner on the audit resulting in this independent auditor's report is Sonya Fraser.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Halifax, Canada
February 14, 2020

# 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 sheets of Emera Incorporated (the "Company") as of December 31, 2019 and 2018, the related 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 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, 2019 and 2018, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2019, 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 audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits 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 audits 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 audits 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 audits 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 audits provide a reasonable basis for our opinion.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

We have served as the Company's auditor since 1998.

Halifax, Canada
February 14, 2020

**Emera Incorporated**

# CONSOLIDATED STATEMENTS OF INCOME

| For the<br>millions of Canadian dollars (except per share amounts) | Year ended December 31<br>**2019** | <br>2018 |
|---|---|---|
| **Operating revenues** | | |
| Regulated electric | **$ 4,769** | $ 4,852 |
| Regulated gas | **1,081** | 1,044 |
| Non-regulated | **261** | 628 |
| Total operating revenues (note 6) | **6,111** | 6,524 |
| **Operating expenses** | | |
| Regulated fuel for generation and purchased power (notes 16 and 18) | **1,609** | 1,677 |
| Regulated cost of natural gas | **350** | 388 |
| Non-regulated fuel for generation and purchased power | **66** | 225 |
| Operating, maintenance and general | **1,464** | 1,580 |
| Provincial, state, and municipal taxes | **342** | 340 |
| Depreciation and amortization | **903** | 916 |
| GBPC impairment charge (note 21) | **34** | – |
| Total operating expenses | **4,768** | 5,126 |
| **Income from operations** | **1,343** | 1,398 |
| Income from equity investments (note 7) | **154** | 154 |
| Other income (expenses), net | **12** | (23) |
| Interest expense, net | **738** | 713 |
| **Income before provision for income taxes** | **771** | 816 |
| Income tax expense (note 8) | **61** | 69 |
| **Net income** | **710** | 747 |
| Non-controlling interest in subsidiaries | **2** | 1 |
| Preferred stock dividends | **45** | 36 |
| **Net income attributable to common shareholders** | **$ 663** | $ 710 |
| | | |
| Weighted average shares of common stock outstanding (in millions) (note 10) | | |
| Basic | **240** | 233 |
| Diluted | **240** | 234 |
| Earnings per common share (note 10) | | |
| Basic | **$ 2.76** | $ 3.05 |
| Diluted | **$ 2.76** | $ 3.04 |
| Dividends per common share declared | **$ 2.3750** | $ 2.2825 |

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

**Emera Incorporated**

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| For the<br>millions of Canadian dollars | Year ended December 31<br>**2019** | <br>2018 |
|---|---|---|
| **Net income** | **$ 710** | $ 747 |
| **Other comprehensive income (loss), net of tax** | | |
| Foreign currency translation adjustment | **(402)** | 627 |
| Unrealized gains (losses) on net investment hedges (1) (2) | **78** | (122) |
| Cash flow hedges | | |
| Net derivative gains (losses) | **3** | 2 |
| Less: reclassification adjustment for losses (gains) included in income | **3** | (6) |
| Net effects of cash flow hedges | **6** | (4) |
| Unrealized gains on available-for-sale investment | | |
| Unrealized gain (loss) arising during the period | **-** | - |
| Less: reclassification adjustment for (gains) recognized in income | **-** | (4) |
| Net unrealized holding gains (losses) | **-** | (4) |
| Net change in unrecognized pension and post-retirement benefit obligation (3) | **74** | 9 |
| Other comprehensive income (loss) (4) | **(244)** | 506 |
| **Comprehensive income (loss)** | **466** | 1,253 |
| Comprehensive income (loss) attributable to non-controlling interest | **1** | 4 |
| **Comprehensive Income (loss) of Emera Incorporated** | **$ 465** | $ 1,249 |

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 expense of $1 million (2018 – $9 million tax recovery) for the year ended December 31, 2019.
(3) Net of tax expense of $9 million (2018 – $2 million tax recovery) for the year ended December 31, 2019.
(4) Net of tax expense of $10 million (2018 – $11 million tax recovery) for the year ended December 31, 2019.

**Emera Incorporated**

# CONSOLIDATED BALANCE SHEETS

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 222** | $ 316 |
| Restricted cash (note 31) | **51** | 56 |
| Inventory (note 12) | **467** | 474 |
| Derivative instruments (notes 13 and 14) | **54** | 148 |
| Regulatory assets (note 15) | **121** | 165 |
| Receivables and other current assets (note 17) | **1,486** | 1,620 |
| Assets held for sale (note 4) | **85** | 53 |
| | **2,486** | 2,832 |
| **Property, plant and equipment**, net of accumulated depreciation and amortization of $8,295 and $8,567, respectively (note 19) | **18,167** | 18,712 |
| **Other assets** | | |
| Deferred income taxes | **186** | 175 |
| Derivative instruments (notes 13 and 14) | **33** | 19 |
| Regulatory assets (note 15) | **1,431** | 1,404 |
| Net investment in direct financing lease (note 18) | **473** | 475 |
| Investments subject to significant influence (note 7) | **1,312** | 1,316 |
| Goodwill (note 21) | **5,835** | 6,313 |
| Other long-term assets | **300** | 291 |
| Assets held for sale (note 4) | **1,619** | 777 |
| | **11,189** | 10,770 |
| **Total assets** | **$ 31,842** | $ 32,314 |

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

**Emera Incorporated**

# CONSOLIDATED BALANCE SHEETS (continued)

| As at<br>millions of Canadian dollars | **December 31<br>2019** | December 31<br>2018 |
|---|---|---|
| **Liabilities and Equity** | | |
| **Current liabilities** | | |
| Short-term debt (note 22) | **$ 1,537** | $ 1,186 |
| Current portion of long-term debt (note 24) | **501** | 1,119 |
| Accounts payable | **1,118** | 1,289 |
| Derivative instruments (notes 13 and 14) | **268** | 260 |
| Regulatory liabilities (note 15) | **295** | 251 |
| Other current liabilities (note 23) | **333** | 428 |
| Liabilities associated with assets held for sale (note 4) | **114** | 20 |
| | **4,166** | 4,553 |
| **Long-term liabilities** | | |
| Long-term debt (note 24) | **13,679** | 14,292 |
| Deferred income taxes (note 8) | **1,285** | 1,320 |
| Derivative instruments (notes 13 and 14) | **102** | 105 |
| Regulatory liabilities (note 15) | **1,886** | 2,359 |
| Pension and post-retirement liabilities (note 20) | **460** | 641 |
| Other long-term liabilities (notes 7 and 25) | **764** | 684 |
| Long-term liabilities associated with assets held for sale (note 4) | **899** | 2 |
| | **19,075** | 19,403 |
| **Equity** | | |
| Common stock (note 9) | **6,216** | 5,816 |
| Cumulative preferred stock (note 27) | **1,004** | 1,004 |
| Contributed surplus | **78** | 84 |
| Accumulated other comprehensive income (note 11) | **95** | 338 |
| Retained earnings | **1,173** | 1,075 |
| Total Emera Incorporated equity | **8,566** | 8,317 |
| Non-controlling interest in subsidiaries (note 28) | **35** | 41 |
| Total equity | **8,601** | 8,358 |
| **Total liabilities and equity** | **$ 31,842** | $ 32,314 |

Commitments and contingencies (note 26)

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<br>millions of Canadian dollars | Year ended December 31<br>2019 | <br>2018 |
|---|---|---|
| **Operating activities** | | |
| Net income | **$ 710** | $ 747 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | **911** | 928 |
| Income from equity investments, net of dividends | **(83)** | (75) |
| Allowance for equity funds used during construction | **(21)** | (19) |
| Deferred income taxes, net | **125** | 185 |
| Net change in pension and post-retirement liabilities | **(17)** | 11 |
| Regulated fuel adjustment mechanism | **(46)** | (16) |
| Net change in fair value of derivative instruments | **(39)** | 55 |
| Net change in regulatory assets and liabilities | **44** | 51 |
| Net change in capitalized transportation capacity | **(55)** | (105) |
| GBPC impairment charge (note 21) | **34** | – |
| Other operating activities, net | **35** | 44 |
| Changes in non-cash working capital (note 29) | **(73)** | (116) |
| **Net cash provided by operating activities** | **1,525** | 1,690 |
| **Investing activities** | | |
| Additions to property, plant and equipment | **(2,495)** | (2,162) |
| Net purchase of investments subject to significant influence, inclusive of acquisition costs | **(3)** | (49) |
| Proceeds from dispositions (note 4) | **875** | – |
| Other investing activities | **6** | 21 |
| **Net cash used in investing activities** | **(1,617)** | (2,190) |
| **Financing activities** | | |
| Change in short-term debt, net | **413** | 99 |
| Proceeds from short-term debt with maturities greater than 90 days | **–** | 129 |
| Repayment of short-term debt with maturities greater than 90 days | **–** | (390) |
| Proceeds from long-term debt, net of issuance costs | **1,066** | 1,055 |
| Retirement of long-term debt | **(1,103)** | (757) |
| Net borrowings (repayments) under committed credit facilities | **(118)** | 321 |
| Issuance of common stock, net of issuance costs | **203** | 10 |
| Issuance of preferred stock, net of issuance costs (note 27) | **–** | 291 |
| Dividends on common stock | **(378)** | (346) |
| Dividends on preferred stock | **(45)** | (36) |
| Other financing activities | **(24)** | (32) |
| **Net cash provided by financing activities** | **14** | 344 |
| Effect of exchange rate changes on cash, cash equivalents, and restricted cash | **(20)** | 25 |
| **Net decrease in cash, cash equivalents, restricted cash and assets held for sale** | **(98)** | (131) |
| Cash, cash equivalents, and restricted cash, beginning of year | **372** | 503 |
| Cash, cash equivalents, restricted cash and assets held for sale, end of year | **$ 274** | $ 372 |
| **Cash, cash equivalents, restricted cash and assets held for sale consists of:** | | |
| Cash | **$ 222** | $ 273 |
| Short-term investments | **–** | 43 |
| Restricted cash | **51** | 56 |
| Assets held for sale | **1** | – |
| Cash, cash equivalents, restricted cash and assets held for sale | **$ 274** | $ 372 |

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, 2018 | **$ 5,816** | **$ 1,004** | **$ 84** | **$ 338** | **$ 1,075** | **$ 41** | **$ 8,358** |
| Net income of Emera Incorporated | **–** | **–** | **–** | **–** | **708** | **2** | **710** |
| Other comprehensive loss, net of tax expense of $10 million | **–** | **–** | **–** | **(243)** | **–** | **(1)** | **(244)** |
| Dividends declared on preferred stock (note 27) | **–** | **–** | **–** | **–** | **(45)** | **–** | **(45)** |
| Dividends declared on common stock ($2.3750/share) | **–** | **–** | **–** | **–** | **(565)** | **–** | **(565)** |
| Common stock issued under purchase plan | **195** | **–** | **–** | **–** | **–** | **–** | **195** |
| Issuance of common stock, net of after-tax issuance costs | **99** | **–** | **–** | **–** | **–** | **–** | **99** |
| Senior management stock options exercised | **104** | **–** | **(7)** | **–** | **–** | **–** | **97** |
| Issuance of preferred shares of GBPC, net of issuance costs (note 28) | **–** | **–** | **–** | **–** | **–** | **14** | **14** |
| Redemption of preferred shares of GBPC (note 28) | **–** | **–** | **–** | **–** | **–** | **(19)** | **(19)** |
| Other | **2** | **–** | **1** | **–** | **–** | **(2)** | **1** |
| **Balance, December 31, 2019** | **$ 6,216** | **$ 1,004** | **$ 78** | **$ 95** | **$ 1,173** | **$ 35** | **$ 8,601** |
| 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 |

(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, 2019 and 2018

## 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.

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations.

At December 31, 2019, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility, serving approximately 779,000 customers in West Central Florida;
- Canadian Electric Utilities which includes:
    - Nova Scotia Power Inc. ("NSPI"), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 523,000 customers; and
    - 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 full power in the second half of 2020. ENL's two investments are:
        - a 100 per cent investment in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.6 billion transmission project, including two 170-kilometre sub-sea 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 Nalcor recognized the first flow of energy from Labrador to Newfoundland in June 2018. Nalcor continues to work towards commissioning the LIL, which is forecasted to be in 2020.
- Other Electric Utilities, which includes:
    - Emera Maine, a regulated electric transmission and distribution utility, serving approximately 159,000 customers in the state of Maine. On March 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in early 2020, subject to approval of the Maine Public Utilities Commission ("MPUC"). Refer to note 4 for further details; and
    - Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities that include:
        - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated regulated electric utility on the island of Barbados, serving approximately 131,000 customers;
        - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 18,000 customers. On September 1, 2019, Grand Bahama Island was struck by Hurricane Dorian, causing significant damage. Refer to note 15 and 21 for further details;
        - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), a vertically integrated regulated electric utility on the island of Dominica, serving approximately 31,000 customers; and
        - a 19.1 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

- Gas Utilities and Infrastructure which includes:
  - Peoples Gas System ("PGS"), a regulated gas distribution utility, serving approximately 406,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 534,000 customers in New Mexico;
  - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida;
  - 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; and
  - a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, which transports natural gas throughout markets in Atlantic Canada and the northeastern United States.

At December 31, 2019, Emera's investments in other energy-related non-regulated companies (included within the Other reportable segment) include 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;
  - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; 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 ("Emera Finance") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
- Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; and
- other investments.

In 2019, the Company completed the sale of assets previously included in the Other segment, including the sale of Emera Energy's New England Gas Generating ("NEGG") and Bayside facilities, and Emera Utility Services ("EUS") equipment and inventory. Refer to note 4 for further details of these transactions.

## 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. Refer to note 31 for further details. 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 or whether any reconsideration events have arisen with respect to existing 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 15 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 is recorded in Other Comprehensive Income ("OCI").

## 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 occurs 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 occurs 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.

### 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.

## LEASES

The Company determines whether a contract contains a lease at inception by evaluating if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Emera has leases with independent power producers and other utilities with annual requirements to purchase wind and hydro energy over varying contract lengths that are classified as finance leases. These finance leases are not recorded on the Company's Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as "Regulated fuel for generation and purchased power" on the Consolidated Statements of Income.

Operating lease liabilities and right-of-use ("ROU") assets are recognized on the Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera's leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as "Operating, maintenance and general" on the Consolidated Statements of Income.

Where the Company is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that 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 is recorded as unearned income at the inception of the lease. 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.

For sales-type leases, the accounting is similar to the accounting for direct finance leases, however the difference between the fair value and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

Emera has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component for all leases.

## 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 costs, 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 to reflect the amount of deferred income tax asset 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 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 8 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 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. 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 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. Tampa Electric and PGS have no derivatives related to hedging as a result of a Florida Public Service Commission approved five-year moratorium on hedging of natural gas purchases which ends on December 31, 2022.

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. There were no short-term investments at December 31, 2019 (2018 – $43 million with an effective interest rate of 2.0 per cent).

## 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 assessments may be conducted on new customers. Deposits are requested accounts as required. 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.

## ASSET IMPAIRMENT

### Long-Lived Assets

Emera assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or sale of a business.

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.

As a result of the damage caused by Hurricane Dorian, the Company completed an asset impairment analysis in Q4 2019. Property, plant and equipment and inventory with a book value of approximately $18 million USD was determined to be impaired and was reclassified as a regulatory asset. GBPC recorded an offsetting insurance receivable of $15 million USD against this regulatory asset. It is anticipated that the regulatory asset balance of $3 million USD remaining at December 31, 2019 will be recovered through insurance. Refer to note 15 for further details. No impairment was recorded in 2018.

### 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 and 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.

In Q4 2019, the Company performed quantitative impairment assessments at the reporting unit level. The quantitative assessments for Tampa Electric, PGS and NMGC concluded that the fair value of the reporting units exceeded their respective carrying amounts. However, it was determined that including the impacts of Hurricane Dorian, the fair value of GBPC did not exceed its carrying amount. As a result of this assessment, a goodwill impairment charge of $30 million was recorded in 2019 due to a decrease in expected future cash flows resulting from the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC. No impairment was recorded in 2018. Refer to note 21 for further details.

Emera Maine's assets and liabilities are classified as held for sale, including $148 million of goodwill, and are 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 goodwill is not impaired. Refer to notes 4 and 21 for further details.

### 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. No impairment of equity method investments was required for either 2018 or 2019.

### 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. No material impairment of financial assets was required for either 2018 or 2019.

## 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, 2019 and 2018, 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; a performance share unit ("PSU") plan; and a restricted share unit ("RSU") 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. The components of net periodic benefit cost other than the service cost component are included in "Other income (expense), net" on the Consolidated Statements of Income.

## 2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2019, are described as follows:

### LEASES

On January 1, 2019, the Company adopted Accounting Standard Updates ("ASU") 2016-02, *Leases (Topic 842)*, including all related amendments, using the modified retrospective approach. The standard requires lessees to recognize leases on the balance sheet for all leases with a term of longer than twelve months and disclose key information about leasing arrangements.

As permitted by the optional transition method, Emera did not restate comparative financial information in the Company's consolidated financial statements, did not reassess whether any expired or existing contracts contained leases and carried forward existing lease classifications. Additionally, the Company elected to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under the leasing guidance within ASC Topic 840. The Company elected to use hindsight to determine the lease term for existing leases and elected to not separate lease components from non-lease components for all lessee and lessor arrangements.

Emera has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There were no updates to information technology systems as a result of implementation.

The Company's adoption of this new standard resulted in right-of-use ("ROU") assets and lease liabilities of approximately $58 million as of January 1, 2019. The ROU assets and lease liabilities were measured at the present value of remaining lease payments using the Company's incremental borrowing rate.

There was no impact to opening retained earnings as at January 1, 2019 or the Company's net income or cash flows for the year ended December 31, 2019 as a result of the adoption of the standard. There were no significant impacts to Emera's accounting for lessor arrangements. Refer to note 18 of the consolidated financial statements for further detail.

### TARGETED IMPROVEMENTS TO ACCOUNTING FOR HEDGING ACTIVITIES

On January 1, 2019, the Company adopted 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. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

### CLOUD COMPUTING

In August 2018, the Financial Accounting Standards Board ("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 is 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 early adopted the standard effective January 1, 2019 and elected to apply the guidance prospectively. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

# 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.

## 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. The Company adopted ASU 2016-13 effective January 1, 2020, with no significant changes to accounting and disclosure identified related to the adoption of the standard.

## SIMPLIFYING THE ACCOUNTING FOR INCOME TAXES

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes*. The standard simplifies the accounting for income taxes by eliminating certain exceptions to the guidance in ASC 740 related to the approach for intraperiod tax allocation, simplifies aspects of accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard will be applied on both a prospective and retrospective basis. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

# 4. DISPOSITIONS

## HELD FOR SALE

### Emera Maine

On March 25, 2019, Emera announced the sale of Emera Maine for a total enterprise value of approximately $1.3 billion USD including cash proceeds of $959 million USD, transferred debt and a working capital adjustment on close. The transaction is expected to close in early 2020, subject to the approval of the MPUC. All other required regulatory approvals have been received. A material gain on the sale is expected to be recognized in earnings at closing.

Emera Maine's assets and liabilities are classified as held for sale and are 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. The Company will continue to record depreciation on these assets, through the transaction closing date, as the depreciation continues to be reflected in customer rates and will be reflected in the carryover basis of the assets when sold. Depreciation and amortization of $39 million ($29 million USD) has been recorded on these assets from March 25, 2019, the date they were classified as held for sale to December 31, 2019.

Details of Emera Maine's assets and liabilities classified as held for sale are as follows:

| As at<br>millions of Canadian dollars | | December 31<br>2019 |
|---|---|---|
| Regulatory assets | $ | 16 |
| Receivables and other current assets | | 69 |
| **Current assets held for sale** | | **85** |
| Property, plant and equipment | | 1,293 |
| Goodwill | | 148 |
| Regulatory assets | | 122 |
| Other long-term assets | | 56 |
| **Long-term assets held for sale** | | **1,619** |
| **Total assets held for sale** | **$** | **1,704** |
| | | |
| Regulatory liabilities | $ | 11 |
| Accounts payable and other current liabilities | | 103 |
| **Current liabilities associated with assets held for sale** | | **114** |
| Long-term debt | | 467 |
| Deferred income taxes | | 204 |
| Regulatory liabilities | | 145 |
| Other long-term liabilities | | 83 |
| **Long-term liabilities associated with assets held for sale** | | **899** |
| **Total liabilities associated with assets held for sale** | **$** | **1,013** |

## DISPOSITIONS

### New England Gas Generation

On March 29, 2019, Emera completed the sale of its three NEGG facilities for cash proceeds of $799 million ($598 million USD) including a working capital adjustment. The NEGG assets were classified as held for sale at December 31, 2018 and the Company ceased depreciation of these assets on November 27, 2018. The NEGG facilities were included within the Company's Other reportable segment. The earnings impact of this sale transaction was immaterial.

Details of NEGG's assets and liabilities classified as held for sale at December 31, 2018 are as follows:

| As at<br>millions of Canadian dollars | | December 31<br>2018 |
|---|---|---|
| Receivables and other current assets | $ | 40 |
| Inventory | | 13 |
| **Current assets held for sale** | | **53** |
| Property, plant and equipment | | 777 |
| **Long-term assets held for sale** | | **777** |
| **Total assets held for sale** | **$** | **830** |
| | | |
| Accounts payable and other current liabilities | $ | 20 |
| **Current liabilities associated with assets held for sale** | | **20** |
| Other long-term liabilities | | 2 |
| **Long-term liabilities associated with assets held for sale** | | **2** |
| **Total liabilities associated with assets held for sale** | **$** | **22** |

**Other**

On March 5, 2019, the Company completed the sale of its Bayside facility for cash proceeds of $46 million. The Bayside facility was included within the Company's Other reportable segment. The earnings impact of this sale transaction was immaterial.

On December 20, 2019, Emera completed the sale of EUS assets. EUS ceased operations on September 30, 2019, and there was no material impact on Emera's balance sheet or earnings as a result of this transaction.

## 5. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part to their different operating, regulatory and geographical 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.

Effective January 1, 2019, Emera revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations. All comparative segment financial information has been restated with no impact to reported consolidated results.

The five new reportable segments are:

- Florida Electric Utility;
- Canadian Electric Utilities;
- Other Electric Utilities;
- Gas Utilities and Infrastructure; and
- Other

| millions of Canadian dollars | Florida Electric Utility | Canadian Electric Utilities | Other Electric Utilities | Gas Utilities and Infrastructure | Other | Inter-segment Eliminations | Total |
|---|---|---|---|---|---|---|---|
| **For the year ended December 31, 2019** | | | | | | | |
| Operating revenues from external customers (1) | **$ 2,596** | **$ 1,429** | **$ 744** | **$ 1,097** | **$ 245** | **$ -** | **$ 6,111** |
| Inter-segment revenues (1) | **11** | **1** | **-** | **22** | **37** | **(71)** | **-** |
| Total operating revenues | **2,607** | **1,430** | **744** | **1,119** | **282** | **(71)** | **6,111** |
| AFUDC – debt and equity | **20** | **6** | **5** | **2** | **-** | **-** | **33** |
| Depreciation and amortization | **445** | **231** | **107** | **109** | **11** | **-** | **903** |
| Interest expense, net | **154** | **142** | **52** | **59** | **331** | **-** | **738** |
| Internally allocated interest (2) | **-** | **-** | **-** | **14** | **(14)** | **-** | **-** |
| Income from equity investments | **-** | **91** | **5** | **22** | **36** | **-** | **154** |
| Income tax expense (recovery) | **79** | **(10)** | **11** | **48** | **(67)** | **-** | **61** |
| Operating, maintenance and general ("OM&G") | **554** | **313** | **195** | **319** | **130** | **(47)** | **1,464** |
| GBPC impairment charge | **-** | **-** | **34** | **-** | **-** | **-** | **34** |
| Net income (loss) attributable to common shareholders | **419** | **229** | **45** | **183** | **(213)** | **-** | **663** |
| Capital expenditures | **1,393** | **384** | **195** | **448** | **63** | **-** | **2,483** |
| **As at December 31, 2019** | | | | | | | |
| Total assets | **16,214** | **6,717** | **3,069** | **5,489** | **1,459** | **(1,106)**(3) | **31,842** |
| Investments subject to significant influence | **-** | **1,133** | **41** | **138** | **-** | **-** | **1,312** |
| Goodwill | **4,544** | **-** | **70** | **1,218** | **3** | **-** | **5,835** |

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that 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) Segment net income is reported on a basis that includes internally allocated financing costs.
(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

| millions of Canadian dollars | Florida Electric Utility | Canadian Electric Utilities | Other Electric Utilities | Gas Utilities and Infrastructure | Other | Inter-segment Eliminations | Total |
|---|---|---|---|---|---|---|---|
| **For the year ended December 31, 2018** | | | | | | | |
| Operating revenues from external customers (1) | $ 2,670 | $ 1,437 | $ 745 | $ 1,062 | $ 610 | $ - | $ 6,524 |
| Inter-segment revenues (1) | 9 | 3 | – | 36 | 51 | (99) | – |
| Total operating revenues | 2,679 | 1,440 | 745 | 1,098 | 661 | (99) | 6,524 |
| AFUDC – debt and equity | 20 | 6 | 3 | 1 | – | – | 30 |
| Depreciation and amortization | 405 | 219 | 114 | 129 | 49 | – | 916 |
| Interest expense, net | 132 | 139 | 48 | 55 | 339 | – | 713 |
| Internally allocated interest (2) | – | – | – | 14 | (14) | – | – |
| Income from equity investments | – | 87 | 6 | 22 | 39 | – | 154 |
| Income tax expense (recovery) | 85 | 8 | 9 | 47 | (80) | – | 69 |
| OM&G | 667 | 286 | 188 | 295 | 206 | (62) | 1,580 |
| Net income (loss) attributable to common shareholders | 381 | 218 | 85 | 135 | (109) | – | 710 |
| Capital expenditures | 1,217 | 345 | 187 | 330 | 72 | – | 2,151 |
| **As at December 31, 2018** | | | | | | | |
| Total assets | 15,997 | 6,275 | 3,094 | 5,404 | 2,653 | (1,109)(3) | 32,314 |
| Investments subject to significant influence | – | 1,079 | 77 | 155 | 5 | – | 1,316 |
| Goodwill | 4,774 | – | 260 | 1,279 | – | – | 6,313 |

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that 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) Segment net income is reported on a basis that includes internally allocated financing costs.
(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

## GEOGRAPHICAL INFORMATION

Revenues (1):

| For the millions of Canadian dollars | Year ended December 31 2019 | 2018 |
|---|---|---|
| Canada | **$ 1,497** | $ 1,520 |
| United States | **4,140** | 4,537 |
| Barbados | **320** | 319 |
| The Bahamas | **112** | 121 |
| Dominica | **42** | 27 |
| | **$ 6,111** | $ 6,524 |

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

Property Plant and Equipment:

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Canada | **$ 4,248** | $ 4,128 |
| United States (1) | **13,095** | 13,739 |
| Barbados | **462** | 446 |
| The Bahamas | **282** | 315 |
| Dominica | **80** | 84 |
| | **$ 18,167** | $ 18,712 |

(1) Excludes Emera Maine balances classified as held for sale as at December 31, 2019. Refer to note 4 for further details.

## 6. REVENUE

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

| millions of Canadian dollars | Florida Electric Utility | Canadian Electric Utilities | Other Electric Utilities | Gas Utilities and Infrastructure | Other | Inter-segment Eliminations | Total |
|---|---|---|---|---|---|---|---|
| **For the year ended December 31, 2019** | | | | | | | |
| **Regulated** | | | | | | | |
| Electric Revenue | | | | | | | |
| Residential | $ 1,387 | $ 746 | $ 276 | $ – | $ – | $ – | $ 2,409 |
| Commercial | 745 | 400 | 339 | – | – | – | 1,484 |
| Industrial | 207 | 210 | 44 | – | – | – | 461 |
| Other electric and regulatory deferrals | 246 | 45 | 13 | – | – | – | 304 |
| Other (1) | 22 | 29 | 72 | – | – | (12) | 111 |
| Regulated electric revenue | 2,607 | 1,430 | 744 | – | – | (12) | 4,769 |
| Gas Revenue | | | | | | | |
| Residential | – | – | – | 502 | – | – | 502 |
| Commercial | – | – | – | 298 | – | – | 298 |
| Industrial | – | – | – | 50 | – | – | 50 |
| Finance income (2) (3) | – | – | – | 60 | – | – | 60 |
| Other | – | – | – | 193 | – | (22) | 171 |
| Regulated gas revenue | – | – | – | 1,103 | – | (22) | 1,081 |
| **Non-Regulated** | | | | | | | |
| Marketing and trading margin (4) | – | – | – | – | 31 | – | 31 |
| Energy sales (4) | – | – | – | – | 80 | (12) | 68 |
| Capacity | – | – | – | – | 38 | – | 38 |
| Other | – | – | – | 16 | 31 | (25) | 22 |
| Mark-to-market (3) | – | – | – | – | 102 | – | 102 |
| Non-regulated revenue | – | – | – | 16 | 282 | (37) | 261 |
| Total operating revenues | **$ 2,607** | **$ 1,430** | **$ 744** | **$ 1,119** | **$ 282** | **$ (71)** | **$ 6,111** |

(1) Other includes 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.

| millions of Canadian dollars | Florida Electric Utility | Canadian Electric Utilities | Other Electric Utilities | Gas Utilities and Infrastructure | Other | Inter-segment Eliminations | Total |
|---|---|---|---|---|---|---|---|
| **For the year ended December 31, 2018** | | | | | | | |
| **Regulated** | | | | | | | |
| Electric Revenue | | | | | | | |
| Residential | $ 1,384 | $ 731 | $ 261 | $ – | $ – | $ – | $ 2,376 |
| Commercial | 755 | 405 | 350 | – | – | – | 1,510 |
| Industrial | 209 | 233 | 46 | – | – | – | 488 |
| Other electric and regulatory deferrals | 312 | 43 | 16 | – | – | – | 371 |
| Other (1) | 19 | 28 | 72 | – | – | (12) | 107 |
| Regulated electric revenue | 2,679 | 1,440 | 745 | – | – | (12) | 4,852 |
| Gas Revenue | | | | | | | |
| Residential | – | – | – | 492 | – | – | 492 |
| Commercial | – | – | – | 291 | – | – | 291 |
| Industrial | – | – | – | 49 | – | – | 49 |
| Finance income (2) (3) | – | – | – | 57 | – | – | 57 |
| Other | – | – | – | 191 | – | (36) | 155 |
| Regulated gas revenue | – | – | – | 1,080 | – | (36) | 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 | 661 | (51) | 628 |
| Total operating revenues | $ 2,679 | $ 1,440 | $ 745 | $ 1,098 | $ 661 | $ (99) | $ 6,524 |

(1) Other includes 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, 2019, the aggregate amount of the transaction price allocated to remaining performance obligations was $347 million (2018 – $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.

# 7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

| millions of Canadian dollars | Carrying Value As at December 31 | | Equity Income For the year ended December 31 | | Percentage of ownership |
|---|---|---|---|---|---|
| | **2019** | 2018 | **2019** | 2018 | **2019** |
| LIL (1) | **$ 579** | $ 534 | **$ 45** | $ 42 | **49.5** |
| NSPML | **554** | 545 | **46** | 45 | **100.0** |
| M&NP (2) | **138** | 155 | **22** | 22 | **12.9** |
| Lucelec (2) | **41** | 42 | **3** | 3 | **19.1** |
| Bear Swamp (3) | **–** | – | **35** | 38 | **50.0** |
| Other Investments | **–** | 40 | **3** | 4 | |
| | **$ 1,312** | $ 1,316 | **$ 154** | $ 154 | |

(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 2015. Bear Swamp's credit investment balance of $137 million (2018 – $172 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a $14 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 31). NSPML's consolidated summarized balance sheets are illustrated as follows:

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| **Balance Sheets** | | |
| Current assets | **$ 69** | $ 86 |
| Property, plant and equipment | **1,671** | 1,690 |
| Regulatory assets | **177** | 108 |
| Non-current assets | **32** | 32 |
| Total assets | **$ 1,949** | $ 1,916 |
| Current liabilities | **$ 23** | $ 21 |
| Long-term debt (1) | **1,288** | 1,288 |
| Non-current liabilities | **84** | 62 |
| Equity | **554** | 545 |
| Total liabilities and equity | **$ 1,949** | $ 1,916 |

(1) The project debt has been guaranteed by the Government of Canada.

## 8. 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 | | 2019 | | 2018 |
|---|---|---|---|---|
| Income before provision for income taxes | $ | **771** | $ | 816 |
| Statutory income tax rate | | **31%** | | 31% |
| Income taxes, at statutory income tax rate | | **239** | | 253 |
| Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities | | **(66)** | | (59) |
| Foreign tax rate variance | | **(49)** | | (55) |
| Amortization of deferred income tax regulatory liabilities | | **(36)** | | (37) |
| Tax effect of equity earnings | | **(15)** | | (15) |
| GBPC impairment charge | | **11** | | – |
| Investment tax credits | | **(9)** | | (4) |
| Change in treatment of NMGC net operating loss carryforwards | | **(7)** | | – |
| Florida state tax apportionment adjustment | | **–** | | (23) |
| Change in prior year unrecognized tax benefits at NSPI | | **–** | | 7 |
| Other | | **(7)** | | 2 |
| Income tax expense | $ | **61** | $ | 69 |
| Effective income tax rate | | **8%** | | 8% |

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 | | 2019 | | 2018 |
|---|---|---|---|---|
| Current income taxes | | | | |
| Canada | $ | **(19)** | $ | 3 |
| United States | | **(46)** | | (121) |
| Other | | **1** | | 2 |
| Deferred income taxes | | | | |
| Canada | | **45** | | 11 |
| United States | | **137** | | 215 |
| Other | | **–** | | (4) |
| Investment tax credits | | | | |
| United States | | **(9)** | | (4) |
| Operating loss carryforwards | | | | |
| Canada | | **(48)** | | (33) |
| Income tax expense (recovery) | $ | **61** | $ | 69 |

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 | | 2019 | | 2018 |
|---|---|---|---|---|
| Canada | $ | **98** | $ | 127 |
| United States | | **682** | | 646 |
| Other | | **(9)** | | 43 |
| Income before provision for income taxes | $ | **771** | $ | 816 |

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 | 2019 | 2018 |
|---|---|---|
| **Deferred income tax assets:** | | |
| Tax loss carryforwards | **$ 908** | $ 917 |
| Tax credit carryforwards | **311** | 269 |
| Regulatory liabilities – cost of removal | **195** | 206 |
| Derivative instruments | **145** | 90 |
| Pension and post-retirement liabilities | **84** | 126 |
| Other | **329** | 441 |
| Total deferred income tax assets before valuation allowance | **1,972** | 2,049 |
| Valuation allowance | **(193)** | (163) |
| Total deferred income tax assets after valuation allowance | **$ 1,779** | $ 1,886 |
| **Deferred income tax (liabilities):** | | |
| Property, plant and equipment | **$ (2,382)** | $ (2,591) |
| Derivative instruments | **(148)** | (124) |
| Other | **(348)** | (316) |
| Total deferred income tax liabilities | **$ (2,878)** | $ (3,031) |
| **Consolidated Balance Sheets presentation:** | | |
| Long-term deferred income tax assets | **$ 186** | $ 175 |
| Long-term deferred income tax liabilities | **(1,285)** | (1,320) |
| Net deferred income tax liabilities | **$ (1,099)** | $ (1,145) |

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 $193 million has been recorded as at December 31, 2019 (2018 – $163 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, 2019 consisted of the following:

| millions of Canadian dollars | Gross Tax Carryforwards | Unrecognized Amounts | Net Tax Carryforwards | Expiration Period |
|---|---|---|---|---|
| Canada | | | | |
| NOL | $ 1,131 | $ (554) | $ 577 | 2027-2039 |
| Capital loss | 80 | (80) | – | Indefinite |
| United States | | | | |
| Federal NOL | $ 2,394 | $ – | $ 2,394 | 2024-2037 |
| State NOL | 1,174 | – | 1,174 | 2024-2039 |
| Tax credit | 311 | – | 311 | 2020-Indefinite |
| Other | | | | |
| NOL | $ 38 | $ (38) | $ – | 2020-2026 |

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

| millions of Canadian dollars | 2019 | 2018 |
|---|---|---|
| Balance, January 1 | **$ 26** | $ 19 |
| Increases due to tax positions related to current year | **2** | – |
| Increases due to tax positions related to a prior year | **1** | 8 |
| Decreases due to tax positions related to a prior year | **–** | (1) |
| Balance, December 31 | **$ 29** | $ 26 |

The total amount of unrecognized tax benefits as at December 31, 2019 was $29 million (2018 – $26 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $5 million (2018 – $4 million) with $1 million of interest expense recognized in the Consolidated Statements of Income (2018 – $3 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next twelve months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, US and non-US income and withholding taxes, for which deferred taxes might otherwise be required, have not been provided for on a cumulative amount of temporary differences related to investments in foreign subsidiaries of approximately $1.9 billion as at December 31, 2019 (2018 – $1.4 billion). 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, 2019, 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.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute. 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 be similarly reassessed by the CRA 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. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Appeal process is not determinable at this time.

## 9. COMMON STOCK

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

| | | **2019** | | 2018 |
|---|---|---|---|---|
| Issued and outstanding: | millions of shares | millions of Canadian dollars | millions of shares | millions of Canadian dollars |
| Balance, December 31, 2018 | **234.12** | **$ 5,816** | 228.77 | $ 5,601 |
| Conversion of Convertible Debentures | **0.03** | **1** | 0.01 | – |
| Issuance of common stock (1) | **1.77** | **99** | 0.45 | 22 |
| Issued under Purchase Plans at market rate | **3.99** | **202** | 4.87 | 200 |
| Discount on shares purchased under Dividend Reinvestment Plan | **–** | **(7)** | – | (9) |
| Options exercised under senior management share option plan | **2.57** | **104** | 0.02 | 1 |
| Employee Share Purchase Plan | **–** | **1** | – | 1 |
| Balance, December 31, 2019 | **242.48** | **$ 6,216** | 234.12 | $ 5,816 |

(1) As at December 31, 2019 a total of 1.77 million common shares have been issued through Emera's at-the-market equity program ("ATM Program") at an average price of $56.56 per share for gross proceeds of $100 million ($98.7 million net of issuance costs).

On July 11, 2019, Emera established an ATM Program that allows the Company to issue up to $600 million of common shares to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was established under a prospectus supplement to the Company's short-form base shelf prospectus which expires on July 14, 2021. As at December 31, 2019, an aggregate gross sales limit of $500 million remains available for issuance under the ATM program.

As at December 31, 2019, the following common shares were reserved for issuance: 3.9 million (2018 – 6.5 million) under the senior management stock option plan, 0.9 million (2018 – 1 million) under the employee common share purchase plan and 8.8 million (2018 – 12.6 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, 2019, Emera is in compliance with this requirement.

## 10. 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) | **2019** | 2018 |
| **Numerator** | | |
| Net income attributable to common shareholders | **$ 662.8** | $ 709.6 |
| **Diluted numerator** | **662.8** | 709.6 |
| **Denominator** | | |
| Weighted average shares of common stock outstanding | **238.5** | 231.7 |
| Weighted average deferred share units outstanding | **1.4** | 1.3 |
| Weighted average shares of common stock outstanding – basic | **239.9** | 233.0 |
| Stock-based compensation | **0.6** | 0.4 |
| Convertible Debentures | **–** | 0.1 |
| **Weighted average shares of common stock outstanding – diluted** | **240.5** | 233.5 |
| **Earnings per common share** | | |
| Basic | **$ 2.76** | $ 3.05 |
| Diluted | **$ 2.76** | $ 3.04 |

## 11. 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 |
|---|---|---|---|---|---|---|
| For the year ended December 31, 2019 | | | | | | |
| Balance, January 1, 2019 | **$ 654** | **$ (74)** | **$ (7)** | **$ (1)** | **$ (234)** | **$ 338** |
| Other comprehensive income (loss) before reclassifications | **(401)** | **78** | **3** | **–** | **–** | **(320)** |
| Amounts reclassified from accumulated other comprehensive income loss (gain) | **–** | **–** | **3** | **–** | **74** | **77** |
| Net current period other comprehensive income (loss) | **(401)** | **78** | **6** | **–** | **74** | **(243)** |
| **Balance, December 31, 2019** | **$ 253** | **$ 4** | **$ (1)** | **$ (1)** | **$ (160)** | **$ 95** |
| For the year ended December 31, 2018 | | | | | | |
| Balance, January 1, 2018 (1) | $ 30 | $ 48 | $ (3) | $ 3 | $ (243) | $ (165) |
| Other comprehensive income (loss) before reclassifications | 624 | (122) | 2 | – | – | 504 |
| Amounts reclassified from accumulated other comprehensive income loss (gain) | – | – | (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 |

(1) The January 1, 2018 balance of AOCI and Regulatory assets includes a prior period reclassification of $37 million in unrecognized pension and post-retirement benefit costs and $15 million in deferred taxes ($22 million, net of tax) to be consistent with current year presentation.

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

| For the millions of Canadian dollars | Affected line item in the Consolidated Financial Statements | Year ended December 31 2019 | 2018 |
|---|---|---|---|
| **Losses (gain) on derivatives recognized as cash flow hedges** | | | |
| Foreign exchange forwards | Operating revenue – regulated | **$ 3** | $ (5) |
| Power and gas swaps | Non-regulated fuel for generation and purchased power | **–** | (1) |
| Total before tax | | **3** | (6) |
| Total net of tax | | **$ 3** | $ (6) |
| **Net change in available-for-sale investments** | | | |
| | Retained earnings (1) | **–** | (4) |
| Total net of tax | | **$ –** | $ (4) |
| **Net change in unrecognized pension and post-retirement benefit costs** | | | |
| Actuarial losses (gains) | Operating, maintenance and general ("OM&G") | **$ 17** | $ 25 |
| Past service costs (gains) | OM&G | **(1)** | (1) |
| Amounts reclassified into obligations | Pension and post-retirement benefits | **39** | (17) |
| Amounts reclassified into obligations | Regulatory assets | **28** | – |
| Total before tax | | **83** | 7 |
| | Income tax recovery (expense) | **(9)** | 2 |
| Total net of tax | | **$ 74** | $ 9 |
| **Total reclassifications out of AOCI, net of tax, for the period** | | **$ 77** | $ (1) |

(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.

## 12. INVENTORY

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Fuel | **$ 232** | $ 213 |
| Materials | **235** | 241 |
| Emission credits | **–** | 20 |
| | **$ 467** | $ 474 |

## 13. DERIVATIVE INSTRUMENTS

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

| | Derivative Assets | | Derivative Liabilities | |
|---|---|---|---|---|
| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 | **December 31 2019** | December 31 2018 |
| *Cash flow hedges* | | | | |
| Foreign exchange forwards | **$ –** | $ – | **$ 1** | $ 5 |
| | **–** | – | **1** | 5 |
| *Regulatory deferral* | | | | |
| Commodity swaps and forwards | | | | |
| Coal purchases | **8** | 71 | **39** | 1 |
| Power purchases | **23** | 2 | **36** | 1 |
| Natural gas purchases and sales | **2** | 2 | **5** | 4 |
| Heavy fuel oil purchases | **1** | 1 | **–** | 1 |
| Foreign exchange forwards | **2** | 29 | **6** | – |
| | **36** | 105 | **86** | 7 |
| *HFT derivatives* | | | | |
| Power swaps and physical contracts | **19** | 62 | **22** | 76 |
| Natural gas swaps, futures, forwards, physical contracts | **151** | 125 | **381** | 403 |
| | **170** | 187 | **403** | 479 |
| *Other derivatives* | | | | |
| Equity derivatives and interest rate swaps | **1** | 1 | **–** | – |
| | **1** | 1 | **–** | – |
| Total gross current derivatives | **207** | 293 | **490** | 491 |
| Impact of master netting agreements with intent to settle net or simultaneously | **(120)** | (126) | **(120)** | (126) |
| | **87** | 167 | **370** | 365 |
| Current | **54** | 148 | **268** | 260 |
| Long-term | **33** | 19 | **102** | 105 |
| **Total derivatives** | **$ 87** | $ 167 | **$ 370** | $ 365 |

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<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 | **December 31 2019** | December 31 2018 |
| Regulatory deferral | **$ 8** | $ 1 | **$ 8** | $ 1 |
| HFT derivatives | **112** | 125 | **112** | 125 |
| Total impact of master netting agreements with intent to settle net or simultaneously | **$ 120** | $ 126 | **$ 120** | $ 126 |

## CASH FLOW HEDGES

The Company has 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 | **2019** | 2018 | |
| | **Foreign exchange forwards** | Power swaps | Foreign exchange forwards |
| Realized gain (loss) in operating revenue – regulated | **$ (3)** | $ – | $ 5 |
| Realized gain (loss) in non-regulated fuel for generation and purchased power | **–** | 1 | – |
| Total gains (losses) in Net income | **$ (3)** | $ 1 | $ 5 |

| As at | | | December 31 |
|---|---|---|---|
| millions of Canadian dollars | **2019** | | 2018 |
| | **Foreign exchange forwards** | Power swaps | Foreign exchange forwards |
| Total unrealized gain (loss) in AOCI – effective portion, net of tax | **$ (1)** | $ (1) | $ (6) |

The Company expects $1 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, 2019, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

| millions | 2020 |
|---|---|
| Foreign exchange forwards (USD) sales | $ 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 | | **2019** | | 2018 |
| | **Commodity swaps and forwards** | **Foreign exchange forwards** | Commodity swaps and forwards | Foreign exchange forwards |
| Unrealized gain (loss) in regulatory assets | **$ (89)** | **$ (6)** | $ (34) | $ 4 |
| Unrealized gain (loss) in regulatory liabilities | **9** | **(8)** | 29 | 24 |
| Realized (gain) loss in regulatory liabilities | **(2)** | **–** | (8) | – |
| Realized (gain) loss in inventory (1) | **(36)** | **(11)** | (55) | (18) |
| Realized (gain) loss in regulated fuel for generation and purchased power (2) | **3** | **(8)** | (2) | (9) |
| Total change derivative instruments | **$ (115)** | **$ (33)** | $ (70) | $ 1 |

(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, 2019, 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 | 2020 | 2021–2022 |
|---|---|---|
| | Purchases | Purchases |
| Coal (metric tonnes) | – | 1 |
| Natural Gas (Mmbtu) | 12 | 21 |
| Heavy fuel oil (bbls) | – | 1 |
| Power (MWh) | 1 | 3 |

## FOREIGN EXCHANGE SWAPS AND FORWARDS

As at December 31, 2019, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated as regulated deferral that are expected to settle as outlined below:

| | 2020 | 2021–2022 |
|---|---|---|
| Foreign exchange contracts (millions of US dollars) | $ 173 | $ 148 |
| Weighted average rate | 1.3148 | 1.3264 |
| % of USD requirements | 85% | 39% |

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<br>millions of Canadian dollars | Year ended December 31<br>**2019** | <br>2018 |
|---|---|---|
| Power swaps and physical contracts in non-regulated operating revenues | **$ 1** | $ (12) |
| Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues | **281** | 205 |
| Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power | **(6)** | 2 |
| | **$ 276** | $ 195 |

As at December 31, 2019, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

| millions | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|
| Natural gas purchases (Mmbtu) | 424 | 84 | 56 | 41 | 26 |
| Natural gas sales (Mmbtu) | 345 | 33 | 9 | 2 | 2 |
| Power purchases (MWh) | 1 | – | – | – | – |
| Power sales (MWh) | 1 | – | – | – | – |

## OTHER DERIVATIVES

As at December 31, 2019, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations. The equity derivative hedges the return on 2.8 million shares and extends until December of 2020.

| For the<br>millions of Canadian dollars | Year ended December 31<br>**2019** | <br>2018 |
|---|---|---|
| | **Equity derivatives** | Interest rate swaps |
| Unrealized gain in operating, maintenance and general | **$ 1** | $ – |
| Unrealized gain (loss) in interest expense, net | **–** | (1) |
| Realized gain in operating, maintenance and general | **27** | – |
| Total gains (losses) in net income | **$ 28** | $ (1) |

## 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, 2019, the maximum exposure the Company has to credit risk is $860 million (2018 – $1,035 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, 2019 was $259 million (2018 – $346 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, 2019, the Company had $115 million (2018 – $118 million) in financial assets, considered to be past due, which have been outstanding for an average 71 days. The fair value of these financial assets is $106 million (2018 – $107 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, 2019 | | December 31, 2018 | |
|---|---|---|---|---|
| | **millions of Canadian dollars** | **% of total exposure** | millions of Canadian dollars | % of total exposure |
| **Receivables, net** | | | | |
| Regulated utilities | | | | |
| Residential | **$ 344** | **31%** | $ 384 | 28% |
| Commercial | **170** | **15%** | 182 | 13% |
| Industrial | **66** | **6%** | 57 | 4% |
| Other | **131** | **12%** | 84 | 6% |
| | **711** | **64%** | 707 | 51% |
| Trading group | | | | |
| Credit rating of A- or above | **38** | **3%** | 49 | 4% |
| Credit rating of BBB- to BBB+ | **59** | **5%** | 70 | 5% |
| Credit rating of CCC- to CCC+ | **–** | **0%** | 8 | 0% |
| Not rated | **95** | **9%** | 108 | 8% |
| | **192** | **17%** | 235 | 17% |
| Other accounts receivable | **184** | **16%** | 273 | 20% |
| Classification as assets held for sale (1) | **(55)** | **-5%** | – | 0% |
| | **1,032** | **92%** | 1,215 | 88% |
| **Derivative Instruments (current and long-term)** | | | | |
| Credit rating of A- or above | **47** | **4%** | 130 | 9% |
| Credit rating of BBB- to BBB+ | **8** | **1%** | 9 | 1% |
| Not rated | **32** | **3%** | 28 | 2% |
| | **87** | **8%** | 167 | 12% |
| | **$ 1,119** | **100%** | $ 1,382 | 100% |

(1) Emera Maine's assets and liabilities are classified as held for sale. Refer to note 4 for further details.

## CASH COLLATERAL

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

| As at<br>millions of Canadian dollars | **December 31 2019** | December 31 2018 |
|---|---|---|
| Cash collateral provided to others | **$ 101** | $ 103 |
| Cash collateral received from others | **2** | 77 |

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, 2019, the total fair value of these derivatives, in a liability position, was $370 million (December 31, 2018 – $365 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.

## 14. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 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, 2019 |
|---|---|---|---|---|
| millions of Canadian dollars | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| *Regulatory deferral* | | | | |
| Commodity swaps and forwards | | | | |
| Power purchases | $ 23 | $ – | $ – | $ 23 |
| Natural gas purchases and sales | – | 2 | – | 2 |
| Heavy fuel oil purchases | – | 1 | – | 1 |
| Foreign exchange forwards | – | 2 | – | 2 |
| | 23 | 5 | – | 28 |
| *HFT derivatives* | | | | |
| Power swaps and physical contracts | 1 | 3 | 1 | 5 |
| Natural gas swaps, futures, forwards, physical contracts and related transportation | (7) | 46 | 14 | 53 |
| | (6) | 49 | 15 | 58 |
| *Other derivatives* | | | | |
| Equity derivatives | 1 | – | – | 1 |
| | 1 | – | – | 1 |
| **Total assets** | 18 | 54 | 15 | 87 |
| **Liabilities** | | | | |
| *Cash flow hedges* | | | | |
| Foreign exchange forwards | – | 1 | – | 1 |
| | – | 1 | – | 1 |
| *Regulatory deferral* | | | | |
| Commodity swaps and forwards | | | | |
| Coal purchases | – | 31 | – | 31 |
| Power purchases | 36 | – | – | 36 |
| Natural gas purchases and sales | 3 | 2 | – | 5 |
| Foreign exchange forwards | – | 6 | – | 6 |
| | 39 | 39 | – | 78 |
| *HFT derivatives* | | | | |
| Power swaps and physical contracts | 5 | 2 | – | 7 |
| Natural gas swaps, futures, forwards and physical contracts | 2 | 33 | 249 | 284 |
| | 7 | 35 | 249 | 291 |
| **Total liabilities** | 46 | 75 | 249 | 370 |
| **Net assets (liabilities)** | $ (28) | $ (21) | $ (234) | $ (283) |

| 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) |

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2019 was as follows:

| | | | **HFT Derivatives** |
|---|---|---|---|
| millions of Canadian dollars | **Power** | **Natural gas** | **Total** |
| Balance, January 1, 2019 | **$ 3** | **$ 18** | **$ 21** |
| Total realized and unrealized gains (losses) included in non-regulated operating revenues | **(2)** | **(4)** | **(6)** |
| Balance, December 31, 2019 | **$ 1** | **$ 14** | **$ 15** |

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2019 was as follows:

| | | HFT Derivatives | |
|---|---|---|---|
| millions of Canadian dollars | Power | Natural gas | Total |
| Balance, January 1, 2019 | $ 1 | $ 305 | $ 306 |
| Total realized and unrealized gains (losses) included in non-regulated operating revenues | (1) | (56) | (57) |
| Balance, December 31, 2019 | $ – | $ 249 | $ 249 |

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, 2019, 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, 2019 |
|---|---|---|---|---|---|
| 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 | $21.40 – $74.05 | $35.03 |
| | | | Probability of default | 0.01% – 1.14% | 0.21% |
| | | | Discount rate | 0.15% – 6.65% | 2.78% |
| *HFT derivatives – Natural gas swaps, futures, forwards, physical contracts* | 9 | Modelled pricing | Third-party pricing | $1.63 – $7.45 | $2.37 |
| | | | Probability of default | 0.01% – 2.31% | 0.09% |
| | | | Discount rate | 0.01% – 20.93% | 1.55% |
| | 5 | Modelled pricing | Third-party pricing | $1.33 – $8.76 | $5.05 |
| | | | Basis adjustment | $0.00 – $1.31 | $0.76 |
| | | | Probability of default | 0.01% – 3.33% | 0.28% |
| | | | Discount rate | 0.01% – 4.71% | 0.91% |
| **Total assets** | $ 15 | | | | |
| **Liabilities** | | | | | |
| *HFT derivatives – Natural gas swaps, futures, forwards and physical contracts* | $ 228 | Modelled pricing | Third-party pricing | $1.54 – $7.45 | $4.07 |
| | | | Own credit risk | 0.01% – 2.31% | 0.12% |
| | | | Discount rate | 0.01% – 18.63% | 1.89% |
| | 21 | Modelled pricing | Third-party pricing | $1.36 – $9.75 | $5.45 |
| | | | Basis adjustment | $0.00 – $1.31 | $0.91 |
| | | | Own credit risk | 0.01% – 3.33% | 0.06% |
| | | | Discount rate | 0.01% – 3.76% | 0.81% |
| **Total liabilities** | $ 249 | | | | |
| **Net assets (liabilities)** | $ (234) | | | | |

| 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 |
| | | | | Correlation factor | 84.98% – 84.98% | 84.98% |
| | | | | Probability of default | 0.08% – 0.29% | 0.15% |
| | | | | Discount rate | 0.03% – 2.99% | 1.65% |
| *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) | | | | |

The financial liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of long-term debt, as follows:

| As at<br>millions of Canadian dollars | Carrying amount | Fair value | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|---|
| **December 31, 2019** | **\$ 14,180** | **\$ 16,409** | **\$ –** | **\$ 15,598** | **\$ 451** | **\$ 16,049** |
| December 31, 2018 | \$ 15,411 | \$ 15,908 | \$ – | \$ 14,991 | \$ 917 | \$ 15,908 |

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 gain of $78 million was recorded in Other Comprehensive Income for the year ended December 31, 2019 (2018 – $122 million loss after-tax).

## 15. 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 applicable 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<br>millions of Canadian dollars | **December 31 2019** (1) | December 31 2018 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred income tax regulatory assets | **$ 862** | $ 775 |
| Pension and post-retirement medical plan | **380** | 453 |
| Deferrals related to derivative instruments | **81** | 10 |
| Storm restoration regulatory asset | **38** | 32 |
| Stranded cost recovery | **27** | 28 |
| Environmental remediations | **26** | 31 |
| Demand side management ("DSM") deferral | **19** | 24 |
| Unamortized defeasance costs | **19** | 26 |
| Cost recovery clauses | **13** | 75 |
| Other | **87** | 115 |
| | **$ 1,552** | $ 1,569 |
| Current | **$ 121** | $ 165 |
| Long-term | **1,431** | 1,404 |
| Total regulatory assets | **$ 1,552** | $ 1,569 |
| **Regulatory liabilities** | | |
| Deferred income tax regulatory liabilities | **985** | 1,218 |
| Accumulated reserve – cost of removal | **891** | 955 |
| Regulated fuel adjustment mechanism | **115** | 161 |
| Storm reserve | **62** | 76 |
| Cost recovery clauses | **53** | 30 |
| Deferrals related to derivative instruments | **42** | 116 |
| Self-insurance fund (note 31) | **29** | 30 |
| Other | **4** | 24 |
| | **$ 2,181** | $ 2,610 |
| Current | **$ 295** | $ 251 |
| Long-term | **1,886** | 2,359 |
| Total regulatory liabilities | **$ 2,181** | $ 2,610 |

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to note 4 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.

### Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at Tampa Electric, PGS and NMGC. 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.

### Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring 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 its regulator. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, inventory, operating, maintenance or general or property, plant and equipment, depending on the nature of the item being economically hedged.

### Storm Restoration Regulatory Asset

This asset represents storm restoration costs, primarily incurred by GBPC. GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are self-insured. On September 1, 2019, Dorian struck Grand Bahama Island as a Category 5 hurricane, with sustained winds of approximately 285 kilometres per hour. The hurricane stalled over the island for several days, causing significant damage to, or destruction of, homes and businesses served by GBPC. GBPC's generation, transmission and distribution assets sustained damage, including the effect of flooding that resulted from storm surge and rain.

It is currently estimated that restoration costs for GBPC self-insured assets will be approximately $15 million USD. In January 2020, the GBPA approved the recovery of these costs through rates over a five-year period. Approximately $12 million USD ($15 million CAD) of these estimated costs were incurred in 2019, and recorded as a regulatory asset.

Restoration costs associated with Hurricane Matthew in 2016 are being amortized over five years and included in rate base as approved by the Grand Bahama Port Authority ("GBPA") for full recovery. The balance as at December 31, 2019 is $23 million.

### Stranded Cost Recovery

Due to the decommissioning of a GBPC steam turbine in 2012, the GBPA approved the recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base for 2019 and 2018 and is expected to be included in future years.

### Environmental Remediations

This asset is primarily related to PGS costs associated with 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.

### DSM Deferral

The UARB approved 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 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.

### 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, 2019, totalled $740 million (2018 – $759 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").

### 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.

### Accumulated Reserve – Cost of Removal ("COR")

This regulatory liability represents the non-ARO COR reserve in Tampa Electric, PGS, NMGC 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 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")*. As approved on December 6, 2019 as part of NSPI's three-year fuel stability plan, differences between actual fuel costs and fuel revenues recovered from customers for the years 2020 to 2022, will be recovered or returned to customers after 2022.

### 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. In September 2019, Tampa Electric incurred approximately $8 million USD in storm restoration preparation costs for Hurricane Dorian. These costs were charged to the storm reserve regulatory liability.

## REGULATORY ENVIRONMENTS

### Florida Electric Utility

Tampa Electric is regulated by the FPSC. Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission ("FERC"). The FPSC sets rates at a level that allows utilities such as Tampa Electric to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

Tampa Electric's approved regulated return on equity ("ROE") range for 2019 and 2018 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 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.

As of December 31, 2019, Tampa Electric has invested approximately $820 million USD in 600 MW of utility-scale solar photovoltaic projects, which are recoverable through FPSC-approved solar base rate adjustments ("SoBRAs"). Tampa Electric expects to invest an additional $30 million USD in these projects through 2021. AFUDC is being earned on these projects during construction. The FPSC has approved SoBRAs representing a total of 554 MW or $96 million USD annually in estimated revenue requirements for in-service projects. Tampa Electric expects to file its final SoBRA petition for the January 1, 2021 tranche in 2020.

On December 10, 2019, the FPSC approved Tampa Electric's petition to reduce base rates and charges reflecting reduction of the state income tax from 5.5 per cent to 4.46 per cent retroactive from January 1, 2019. The base rate reduction of approximately $5 million USD due to customers is subject to true-up, and the actual rate reduction may vary from year to year.

On October 3, 2019, the FPSC issued a rule to implement a storm protection cost recovery clause. This new clause provides a process for Florida investor-owned utilities, including Tampa Electric, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Subject to final approval of the FPSC rule, Tampa Electric expects to file a storm protection plan with the FPSC in Q2 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 due to 2018 US tax reform benefits. On April 9, 2019, Tampa Electric reached a settlement agreement with consumer parties regarding eligible storm costs as a result of Hurricane Irma in 2017, which was approved by the FPSC on May 21, 2019. As a result, Tampa Electric refunded $12 million USD to customers in January 2020, resulting in minimal impact to the Consolidated Statements of Income.

## Canadian Electric Utilities

### 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 2019 and 2018 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 Act*, was enacted by the Province of Nova Scotia in December 2015, with a goal of providing rate stability and predictability for customers for the 2017 through 2019 period. In March 2016, in accordance with the Electricity Plan Act, NSPI announced that it would not file a General Rate Application ("GRA") for non-fuel electricity rates for the 2017 through 2019 period. The UARB approved NSPI's three-year fuel stability plan for 2017 through 2019, which resulted in an average annual overall rate increase of 1.5 per cent to recover fuel costs for each of these three years.

On December 6, 2019, the UARB approved NSPI's three-year fuel stability plan which results in an average annual overall rate increase of 1.5 per cent to recover fuel costs for the period of 2020 through 2022. For the years 2020 to 2022, differences between actual fuel costs and fuel revenues recovered from customers will be recovered from or returned to customers after 2022. The decision further directed that annual excess non-fuel revenues above NSPI's approved range of ROE are to be applied to the FAM.

In September 2017, the UARB approved NSPI's interim assessment payment to NSP Maritime Link Inc. ("NSPML") of the costs associated with the Maritime Link when it is in service. The UARB approved annual payment for 2019 is $111 million and as of December 31, 2019, $101 million of that has been paid. The payments are subject to a holdback of $10 million pending UARB agreement that a minimum of $10 million 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, 2019, NSPI has recorded a $6 million holdback payable to NSPML.

In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment payments of $110 million and $111 million for 2018 and 2019 respectively, reflect 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 through 2019 fuel rates and were 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 and in 2019, a further $35 million was refunded. The UARB decision to reduce the assessment payable to NSPML in 2018 and 2019 results in the Company recording amounts collected from customers as a FAM regulatory liability, with no material impact on earnings.

The UARB's decision to approve NSPI's 2020 through 2022 Fuel Stability Plan outlined the treatment of the reduced 2019 NSPML assessment of $52 million plus interest. The reduced assessment will be refunded to most customers through a reduction incorporated into their 2020 through 2022 rates and the remaining customers will receive a one-time on bill credit in 2020. The credit to customers will be approximately $40 million plus interest in 2020, with the remaining $12 million plus interest to be returned to customers subsequent to 2022.

On November 27, 2019, the UARB approved the 2020 interim cost assessment recovery from NSPI for costs associated with the Maritime Link of $145 million, subject to a holdback of up to $10 million. Refer to the NSPML section below for further details.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to independent audit. In July 2018, the FAM audit results relating to fiscal 2016 and 2017 were publicly released. A UARB regulatory process is in progress with a hearing held on January 13, 2020.

### NSPML

Equity earnings contributions from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML'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 30 per cent.

On November 27, 2019, the UARB approved NSPML's interim assessment for recovery of 2020 Maritime Link costs from NSPI of approximately $145 million (2019 – $111 million). The total recovery of $145 million includes approximately $115 million of operating and maintenance, debt financing and equity financing costs, and approximately $30 million for depreciation and amortization of financing costs. This payment is subject to a holdback of up to $10 million. Recovery of the $115 million of operating and maintenance, debt financing and equity financing costs began on January 1, 2020. Beginning June 1, 2020, recovery of the $30 million of depreciation and amortization of financing costs will be included in NSPI customer rates, with payment of this recovery to NSPML to begin on the earlier of the confirmation of delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric facility, and November 1, 2020. NSPML expects to file a final cost assessment with the UARB in 2020.

## Other Electric Utilities

### 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 2019 and 2018 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 2019 and 2018.

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 (2018 – 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. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Transmission and Distribution, Storage, Dispatch and Sales. BLPC is negotiating the terms of the new licenses under the amended legislation.

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 2019 and 2018.

All BLPC fuel costs are passed to customers through the fuel pass-through mechanism which provides opportunity to recover all fuel costs in a timely manner. The approved calculation of the fuel charge is adjusted monthly and reported to the regulator.

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 tariff review policy with new rates submitted every three years. GBPC's approved regulated return on rate base was 8.5 per cent for 2019 (2018 – 8.5 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 the all-in rate for electricity (fuel and base rates) would be held at 2016 levels over the five-year period from 2017 through 2021. 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 2019 and 2018.

Domlec fuel costs are passed to customers through a fuel pass-through mechanism which provides opportunity to recover substantially all fuel costs in a timely manner.

## Gas Utilities and Infrastructure

### PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

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. 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 and Cast Iron/Bare Steel Pipe Replacement costs, including a return on capital invested incurred in developing and implementing energy conservation programs. The Cast Iron/ Bare Steel Pipe Replacement clause is 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 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 reduced its 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 during 2020 regardless of its earned ROE at the time, provided the new rates do not become effective before January 1, 2021. On February 7, 2020, PGS notified the FPSC that it is planning to file a new base rate proceeding in April 2020 for new rates effective January 2021.

### NMGC

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to its cost of providing service, plus an appropriate return on invested capital.

The approved ROE for NMGC is 9.1 per cent, on an allowed equity capital structure of 52 per cent.

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.

On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019, and allowed NMGC to retain tax reform benefits realized from January 1, 2018 to the effective date of the new rates. The new rates are being phased in over two years and are expected to result in an annual revenue increase of approximately $3 million USD. The deferred income tax regulatory liability of $11 million ($8 million USD) recorded at December 31, 2018 to reflect deferred tax benefits was recognized in revenue in Q2 2019. The NMPRC also approved the utility's weather adjustment mechanism. Beginning in August 2019, the NMPRC approved a change in the treatment of net operating loss carryforwards. As a result of this change, a tax benefit of approximately $7 million ($5 million USD) was recognized in earnings in Q3 2019.

On December 23, 2019, NMGC filed a future year rate case on December 23, 2019 for new rates effective January 2021. The proposed new rates reflect the recovery of capital investment in pipelines and related infrastructure. The estimated annual incremental revenue requirement is approximately $13 million USD. A decision from the NMPRC is expected in late 2020.

### 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 Canada Energy Board ("CER"). The CER Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the *CER Act* and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

## 16. 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 $107 million for the year ended December 31, 2019 (2018 – $97 million). 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 $63 million for the year ended December 31, 2019 (2018 – $29 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, 2019 and at December 31, 2018.

## 17. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

| As at<br>millions of Canadian dollars | **December 31<br>2019** | December 31<br>2018 |
|---|---|---|
| Customer accounts receivable – billed | **$ 704** | $ 844 |
| Customer accounts receivable – unbilled | **265** | 296 |
| Allowance for doubtful accounts | **(9)** | (11) |
| Other receivables | **72** | 86 |
| Capitalized transportation capacity (1) | **272** | 179 |
| Income tax receivable | **118** | 175 |
| Prepaid expenses | **48** | 42 |
| Net investment in direct financing lease (note 18) | **9** | 9 |
| Other current assets | **7** | – |
| | **$ 1,486** | $ 1,620 |

(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.

# 18. LEASES

## LESSEE

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 66 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

| As at<br>millions of Canadian dollars | Classification | | December 31<br>2019 |
|---|---|---|---|
| Right-of-use asset | Other long-term assets | **$** | **64** |
| Lease liabilities | | | |
| Current | Other current liabilities | | **5** |
| Long-term | Other long-term liabilities | | **61** |
| Total lease liabilities | | **$** | **66** |

The Company has recorded lease expense of $172 million for the year ended December 31, 2019, of which $156 million relates to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the consolidated statements of income.

Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

| millions of Canadian dollars | | 2020 | | 2021 | | 2022 | | 2023 | | 2024 | | Thereafter | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Minimum lease payments | $ | 8 | $ | 8 | $ | 7 | $ | 6 | $ | 5 | $ | 102 | $ | 136 |
| Less imputed interest | | | | | | | | | | | | | | (70) |
| Total | $ | 8 | $ | 8 | $ | 7 | $ | 6 | $ | 5 | $ | 102 | $ | 66 |

Additional information related to Emera's leases is as follows:

| For the | | Year ended December 31<br>2019 |
|---|---|---|
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows for operating leases (millions of Canadian dollars) | $ | 7 |
| Right-of-use assets obtained in exchange for lease obligations: | | |
| Operating leases (millions of Canadian dollars) | $ | 16 |
| Weighted average remaining lease term (years) | | 39 |
| Weighted average discount rate – operating leases | | 4.07% |

## LESSOR

The Company's net investment in direct finance and sales-type leases relate to Brunswick Pipeline, compressed natural gas ("CNG") stations and heat pumps.

Direct finance and sales-type lease 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" and "Other income (expense), net" on the Consolidated Statements of Income.

The Company manages its risk associated with the residual value of the Brunswick Pipeline lease through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets at any time after 2021 by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

Net investment in direct finance and sales-type leases consist of the following (1):

| As at<br>millions of Canadian dollars | | December 31<br>2019 |
|---|---|---|
| Total minimum lease payment to be received | $ | 1,066 |
| Less: amounts representing estimated executory costs | | (189) |
| Minimum lease payments receivable | $ | 877 |
| Estimated residual value of leased property (unguaranteed) | | 183 |
| Less: unearned finance lease income | | (532) |
| Net investment in direct finance and sales-type leases | $ | 528 |
| Principal due within one year (included in "Receivables and other current assets") | | 17 |
| Net investment in sales-type leases – long-term (included in "Other long-term assets") | | 38 |
| Net Investment in direct finance leases – long-term | $ | 473 |

(1) The net investment in direct finance lease balance as of December 31, 2018, primarily related to New Brunswick Pipeline, consisted of net minimum lease payments receivable of $865 million less an unguaranteed residual value of $183 million and unearned finance income of $564 million.

As at December 31, 2019, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

| millions of Canadian dollars | | 2020 | | 2021 | | 2022 | | 2023 | | 2024 | | Thereafter | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Minimum lease payments to be received | $ | 76 | $ | 74 | $ | 73 | $ | 73 | $ | 74 | $ | 696 | $ | 1,066 |
| Less: executory costs | | | | | | | | | | | | | | (189) |
| Minimum lease payments receivable | $ | 76 | $ | 74 | $ | 73 | $ | 73 | $ | 74 | $ | 696 | $ | 877 |

## 19. PROPERTY, PLANT AND EQUIPMENT

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

| As at<br>millions of Canadian dollars | Estimated useful life | | December 31<br>2019 (1) | | December 31<br>2018 |
|---|---|---|---|---|---|
| Generation (2) | 3 to 131 | $ | 11,181 | $ | 11,092 |
| Transmission | 11 to 80 | | 2,318 | | 3,047 |
| Distribution | 4 to 80 | | 5,820 | | 6,348 |
| Gas transmission and distribution | 7 to 85 | | 3,546 | | 3,398 |
| General plant and other | 2 to 60 | | 2,006 | | 2,158 |
| Total cost | | | 24,871 | | 26,043 |
| Less: Accumulated depreciation (2) | | | (8,295) | | (8,567) |
| | | | 16,576 | | 17,476 |
| Construction work in progress | | | 1,591 | | 1,236 |
| Net book value | | $ | 18,167 | $ | 18,712 |

(1) Excludes Emera Maine balances classified as held for sale as at December 31, 2019. Refer to note 4 for further details.
(2) On March 29, 2019, the Company sold its NEGG facilities. As of December 31, 2018, the Company classified these assets as held for sale on the Consolidated Balance Sheets. Refer to note 4 for additional information.

## 20. 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, New Mexico, Barbados, Dominica and Grand Bahama Island. On March 25, 2019, Emera announced the sale of Emera Maine. As at December 31, 2019, Emera Maine's assets and liabilities, including balances related to benefit plans, were classified as held for sale. Refer to note 4 for further details.

### 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 | | **2019** | | 2018 |
| **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 | **$ 2,650** | **$ 350** | $ 2,683 | $ 356 |
| Service cost | **47** | **4** | 51 | 6 |
| Plan participant contributions | **8** | **5** | 8 | 5 |
| Interest cost | **102** | **14** | 95 | 13 |
| Benefits paid | **(130)** | **(23)** | (143) | (33) |
| Actuarial (gains) losses | **231** | **19** | (133) | (25) |
| Settlements and curtailments | **(20)** | **-** | (18) | - |
| Foreign currency translation adjustment | **(66)** | **(16)** | 107 | 28 |
| Balance, December 31 | **2,822** | **353** | 2,650 | 350 |
| **Change in plan assets** | | | | |
| Balance, January 1 | **2,300** | **49** | 2,408 | 45 |
| Employer contributions | **52** | **19** | 51 | 31 |
| Plan participant contributions | **8** | **5** | 8 | 5 |
| Benefits paid | **(130)** | **(23)** | (143) | (33) |
| Actual return on assets, net of expenses | **424** | **7** | (105) | (3) |
| Settlements and curtailments | **(7)** | **-** | (18) | - |
| Foreign currency translation adjustment | **(54)** | **(1)** | 99 | 4 |
| Balance, December 31 | **2,593** | **56** | 2,300 | 49 |
| Funded status, end of year | **$ (229)** | **$ (297)** | $ (350) | $ (301) |

### 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 | | **2019** | | 2018 |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| PBO/APBO | **$ 2,797** | **$ 323** | $ 2,623 | $ 318 |
| Fair value of plan assets | **2,557** | **7** | 2,264 | 6 |
| Funded status | **$ (240)** | **$ (316)** | $ (359) | $ (312) |

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

The ABO for the defined benefit pension plans was $2,687 million as at December 31, 2019 (2018 – $2,527 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 | **2019** | 2018 |
|---|---|---|
| | **Defined benefit pension plans** | Defined benefit pension plans |
| ABO | **$ 2,665** | $ 2,504 |
| Fair value of plan assets | **2,557** | 2,264 |
| Funded status | **$ (108)** | $ (240) |

## BALANCE SHEET

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

| As at<br>millions of Canadian dollars | **December 31 2019** | | December 31 2018 | |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Other current liabilities | **$ (4)** | **$ (18)** | $ (12) | $ (19) |
| Long-term liabilities | **(206)** | **(254)** | (347) | (294) |
| Long-term liabilities associated with assets held for sale (1) | **(30)** | **(44)** | – | – |
| Other long-term assets | **11** | **19** | 9 | 11 |
| Amount included in deferred income tax | **(7)** | **1** | 5 | (2) |
| AOCI, net of tax and regulatory assets | **524** | **72** | 628 | 60 |
| Net amount recognized | **$ 288** | **$ (224)** | $ 283 | $ (244) |

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to note 4 for further details.

## 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. As at December 31, 2019, regulatory asset balances related to Emera Maine have been reclassified as assets held for sale. 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** | | | |
| Balance, January 1, 2019 | $ 389 | $ 246 | $ (2) |
| Amortized in current period | (20) | (17) | 1 |
| Current year addition to AOCI or regulatory assets | 6 | (69) | – |
| Change in foreign exchange rate | (17) | – | – |
| Balance, December 31, 2019 | $ 358 | $ 160 | $ (1) |
| **Non-pension benefits plans** | | | |
| Balance, January 1, 2019 | $ 65 | $ (7) | $ – |
| Amortized in current period | 5 | – | – |
| Current year addition to AOCI or regulatory assets | 11 | 2 | – |
| Change in foreign exchange rate | (3) | – | – |
| Balance, December 31, 2019 | $ 78 | $ (5) | $ – |

| | 2019 | | 2018 | |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Actuarial losses (gains) | **$ 160** | **$ (5)** | $ 246 | $ (7) |
| Past service (gains) costs | **(1)** | **–** | (2) | – |
| Regulatory assets | **358** | **78** | 389 | 65 |
| Total AOCI and regulatory assets before deferred income taxes | **517** | **73** | 633 | 58 |
| Amount included in deferred income tax assets | **7** | **(1)** | (5) | 2 |
| Net amount in AOCI and regulatory assets | **$ 524** | **$ 72** | $ 628 | $ 60 |

## BENEFIT COST COMPONENTS

Emera's net periodic benefit cost included the following:

| As at | | | Year ended December 31 | |
|---|---|---|---|---|
| millions of Canadian dollars | 2019 | | 2018 | |
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Service cost | **$ 47** | **$ 4** | $ 51 | $ 6 |
| Interest cost | **102** | **14** | 95 | 13 |
| Expected return on plan assets | **(147)** | **(2)** | (138) | (2) |
| Current year amortization of: | | | | |
| Actuarial losses | **16** | **–** | 33 | (1) |
| Past service costs (gains) | **(1)** | **–** | (1) | – |
| Regulatory assets (liability) | **20** | **(5)** | 26 | (2) |
| Settlement, curtailments | **1** | **–** | 4 | – |
| Total | **$ 38** | **$ 11** | $ 70 | $ 14 |

The expected return on plan assets is determined based on the market-related value of plan assets of $2,401 million as at January 1, 2019 (2018 – $2,223 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 | 40% to 45% |
| Equities | 55% to 60% |

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, 2019** |
|---|---|---|---|---|---|
| | **NAV** | **Level 1** | **Level 2** | **Total** | **Percentage** |
| Cash and cash equivalents | **$ –** | **$ 44** | **$ –** | **$ 44** | **2%** |
| Net in-transits | **–** | **(48)** | **–** | **(48)** | **−2%** |
| Equity securities: | | | | | |
| Canadian equity | **–** | **210** | **–** | **210** | **8%** |
| US equity | **–** | **388** | **–** | **388** | **15%** |
| Other equity | **–** | **176** | **–** | **176** | **7%** |
| Fixed income securities: | | | | | |
| Government | **–** | **–** | **93** | **93** | **3%** |
| Corporate | **–** | **–** | **126** | **126** | **5%** |
| Other | **–** | **5** | **9** | **14** | **–** |
| Mutual funds | **–** | **199** | **–** | **199** | **8%** |
| Other | **–** | **(5)** | **1** | **(4)** | **–** |
| Open-ended investments measured at NAV (1) | **860** | **–** | **–** | **860** | **33%** |
| Common collective trusts measured at NAV (2) | **535** | **–** | **–** | **535** | **21%** |
| Total | **$ 1,395** | **$ 969** | **$ 229** | **$ 2,593** | **100%** |

| 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% |

(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 14 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 most of the Company's post-retirement benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The primary exceptions to this are the NMGC Retiree Medical Plan, which is fully funded, and the Emera Maine post-retirement benefits plans, which are partially-funded.

## INVESTMENTS IN EMERA

As at December 31, 2019 and 2018, 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 (1) | Non-pension benefit plans (2) |
|---|---|---|
| **Expected employer contributions** | | |
| 2020 | $ 44 | $ 21 |
| **Expected benefit payments** | | |
| 2020 | 143 | 23 |
| 2021 | 154 | 23 |
| 2022 | 158 | 23 |
| 2023 | 165 | 23 |
| 2024 | 173 | 23 |
| 2025–2029 | 959 | 115 |

(1) Includes expected employer contributions related to Emera Maine of $3 million in 2020; and expected benefit payments related to Emera Maine of $10 million in 2020; $10 million in 2021; $11 million in 2022; $11 million in 2023; $12 million in 2024 and $62 million in 2025-2029.

(2) Includes expected employer contributions related to Emera Maine of $3 million in 2020; and expected benefit payments related to Emera Maine of $3 million in 2020; $3 million in 2021; $3 million in 2022; $3 million in 2023; $4 million in 2024 and $17 million in 2025-2029.

## ASSUMPTIONS

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

| | | **2019** | | 2018 |
|---|---|---|---|---|
| (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 – past service | **3.17%** | **3.27%** | 4.05% | 4.30% |
| Discount rate – future service | **3.21%** | **3.28%** | 4.05% | 4.30% |
| Rate of compensation increase | **3.32%** | **3.70%** | 3.30% | 3.67% |
| Health care trend – initial (next year) | **-** | **6.15%** | – | 6.39% |
| – ultimate | **-** | **4.38%** | – | 4.45% |
| – year ultimate reached | **-** | **2038** | – | 2035 |
| **Benefit cost for year ended December 31:** | | | | |
| Discount rate – past and future service | **4.05%** | **4.30%** | 3.55% | 3.65% |
| Expected long-term return on plan assets | **6.50%** | **2.81%** | 6.38% | 3.73% |
| Rate of compensation increase | **3.30%** | **3.67%** | 3.12% | 3.28% |
| Health care trend – initial (current year) | **-** | **6.39%** | – | 6.65% |
| – ultimate | **-** | **4.45%** | – | 4.45% |
| – year ultimate reached | **-** | **2035** | – | 2036 |

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 2019:

| millions of Canadian dollars | Increase | Decrease |
|---|---|---|
| Service cost and interest cost | $ 1 | $ (1) |
| Accumulated post-retirement benefit obligation, December 31 | 16 | (14) |

## SENSITIVITY ANALYSIS FOR DEFINED BENEFIT PENSION PLANS

The impact on the 2019 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 2020:

| millions of Canadian dollars | Defined benefit pension plans | Non-pension benefit plans |
|---|---|---|
| Actuarial gains (losses) | $ (14) | $ – |
| Past service gains | (1) | – |
| Regulatory assets | (29) | (1) |
| Total | $ (44) | $ (1) |

## DEFINED CONTRIBUTION PLAN

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2019 was $34 million (2018 – $31 million).

## 21. GOODWILL

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

| millions of Canadian dollars | **2019** | 2018 |
|---|---|---|
| Balance, January 1 | **$ 6,313** | $ 5,805 |
| Additions | **3** | – |
| GBPC impairment charge | **(30)** | – |
| Classified as assets held for sale (1) | **(148)** | – |
| Change in foreign exchange rate | **(303)** | 508 |
| Balance, December 31 | **$ 5,835** | $ 6,313 |

(1) On March 25, 2019, Emera announced the sale of Emera Maine. Emera Maine's assets and liabilities are classified as held for sale. Refer to note 4 for further details.

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Balance Sheets at December 31, 2019, relates to TECO Energy, Emera Maine and GBPC. Emera's reporting units with goodwill are Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC.

In 2019, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment for Tampa Electric, PGS and New Mexico Gas, respectively, using a combination of the income and market approach. The Company concluded that the fair value of the reporting units exceeded their respective carrying values and, as such, no impairment charges were recognized.

Goodwill on Emera's Consolidated Balance Sheets at December 31, 2018, included $104 million related to GBPC. In 2019, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC using an income approach. This assessment concluded that the fair value of the reporting unit was below its carrying value, including goodwill. Certain assumptions used in determining the fair value of the reporting unit in the 2019 impairment test changed from those used in prior years, including a decrease in expected future cash flows due to the impacts of Hurricane Dorian storm recovery and changes in the anticipated long term regulated capital structure of GBPC.

As a result, Emera recognized an impairment charge of $30 million in 2019 based on the excess of GBPC's carrying amount over its fair value. This non-cash charge is included in "GBPC impairment charge" in the Consolidated Statements of Income. $70 million in goodwill continues to be related to GBPC as at December 31, 2019.

## 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 | 2019 | Weighted average interest rate | 2018 | Weighted average interest rate |
|---|---|---|---|---|
| **TECO Finance** | | | | |
| Advances on revolving credit and term facilities | **$ 656** | **2.39%** | $ 805 | 3.43% |
| **Tampa Electric Company ("TEC")** | | | | |
| Advances on accounts receivable and revolving credit facilities | **452** | **2.56%** | 302 | 3.10% |
| **Emera Inc.** | | | | |
| Non-revolving term facility | **399** | **2.69%** | | |
| Bank indebtedness | **6** | **-%** | - | -% |
| **GBPC** | | | | |
| Advances on revolving credit facilities | **10** | **5.25%** | - | -% |
| **NMGC** | | | | |
| Advances on revolving credit facilities | **8** | **2.70%** | 79 | 3.40% |
| **NSPI** | | | | |
| Bank indebtedness | **6** | **-%** | – | –% |
| **Short-term debt** | **$ 1,537** | | $ 1,186 | |

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 | 2019 | 2018 |
|---|---|---|---|
| TECO Energy/TECO Finance - term credit facility | 2020 | **$ 649** | $ 682 |
| TECO Energy/TECO Finance - revolving credit facility | 2022 | **520** | 546 |
| Tampa Electric Company - revolving credit facility | 2022 | **520** | 443 |
| Emera Inc. - non-revolving term facility | 2020 | **400** | – |
| Tampa Electric Company - accounts receivable revolving credit facility | 2021 | **195** | 205 |
| NMGC - revolving credit facility | 2022 | **162** | 171 |
| GBPC - revolving credit facility | on demand | **17** | 18 |
| Total | | **2,463** | 2,065 |
| Less: | | | |
| Advances under revolving credit and term facilities | | **1,525** | 1,186 |
| Letters of credit issued within the credit facilities | | **3** | 3 |
| Total advances under available facilities | | **1,528** | 1,189 |
| Available capacity under existing agreements | | **$ 935** | $ 876 |

The weighted average interest rate on outstanding short-term debt at December 31, 2019 was 2.54 per cent (2018 - 3.34 per cent).

## RECENT SIGNIFICANT FINANCING ACTIVITIES BY SEGMENT

### Florida Electric Utilities

On February 6, 2020, TEC entered into a $300 million USD non-revolving credit agreement with a maturity date of February 4, 2021. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR, prime rate or the federal funds rate, plus a margin.

On December 19, 2019, TEC increased its $325 million USD revolving credit facility by $75 million USD to $400 million USD. There were no other changes in commercial terms.

### Other

On December 16, 2019, Emera entered into a $400 million non-revolving credit agreement with a maturity date of December 15, 2020. The credit agreement contains customary representations and warranties, events of default, financial and other covenants and bears interest at Bankers Acceptance rates or prime rate advances, plus a margin.

On March 7, 2019, TECO Energy/Finance extended the maturity date of its $500 million USD credit facility from March 8, 2019 to March 5, 2020. There were no other significant changes in commercial terms from the prior agreement.

## 23. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

| As at<br>millions of Canadian dollars | **December 31<br>2019** | December 31<br>2018 |
|---|---|---|
| Accrued charges | **$ 147** | $ 154 |
| Accrued interest on long-term debt | **77** | 93 |
| Pension and post-retirement liabilities (note 20) | **22** | 31 |
| Sales and other taxes payable | **13** | 9 |
| Income tax payable | **1** | 6 |
| Other | **73** | 135 |
| | **$ 333** | $ 428 |

## 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 consisted of the following:

| millions of Canadian dollars | Weighted average interest rate (1) 2019 | 2018 | Maturity | 2019 | 2018 |
|---|---|---|---|---|---|
| **Emera** | | | | | |
| Bankers acceptances, LIBOR loans | Variable | Variable | 2024 | $ **437** | $ 339 |
| Unsecured fixed rate notes | 2.90% | 3.50% | 2023 | **500** | 725 |
| Fixed to floating subordinated notes (USD) | 6.75% | 6.75% | 2076 | **1,559** | 1,637 |
| | | | | $ **2,496** | $ 2,701 |
| **Emera Finance** | | | | | |
| Unsecured senior notes (USD) | 3.86% | 3.60% | 2021–2046 | $ **3,572** | $ 4,434 |
| **TECO Finance** (2) | | | | | |
| Fixed rate notes and bonds (USD) | 5.15% | 5.15% | 2020 | **390** | 409 |
| **Tampa Electric** (3) | | | | | |
| Fixed rate notes and bonds (USD) | 4.53% | 4.64% | 2021–2050 | $ **3,334** | $ 3,126 |
| **PGS** | | | | | |
| Fixed rate notes and bonds (USD) | 4.58% | 4.66% | 2021–2050 | $ **437** | $ 425 |
| **NMGC** | | | | | |
| Fixed rate notes and bonds (USD) | 4.30% | 4.53% | 2021–2049 | $ **474** | $ 368 |
| **NMGI** | | | | | |
| Fixed rate notes and bonds (USD) | 3.64% | 3.41% | 2024 | $ **195** | $ 273 |
| **NSPI** | | | | | |
| Discount notes | Variable | Variable | 2024 | $ **308** | $ 516 |
| Medium term fixed rate notes | 5.37% | 5.73% | 2025–2097 | **2,365** | 1,965 |
| Fixed rate debenture | – | 9.75% | – | **–** | 95 |
| | | | | $ **2,673** | $ 2,576 |
| **Emera Maine** | | | | | |
| LIBOR loans and demand loans | Variable | Variable | 2023 | $ **11** | $ 28 |
| Secured fixed rate mortgage bonds (USD) | 9.74% | 9.74% | 2020–2022 | **65** | 68 |
| Unsecured senior fixed rate notes (USD) | 4.15% | 4.23% | 2022–2049 | **442** | 382 |
| | | | | $ **518** | $ 478 |
| **EBP** | | | | | |
| Senior secured credit facility | Variable | 3.08% | 2023 | $ **248** | $ 248 |
| **ECI** | | | | | |
| Secured senior notes (USD) | Variable | Variable | 2021 | **130** | 159 |
| Amortizing fixed rate notes (USD) | 3.89% | 3.83% | 2021–2022 | **122** | 114 |
| Secured fixed rate senior notes (4) | 4.84% | 5.51% | 2020–2035 | $ **218** | $ 191 |
| | | | | $ **470** | $ 464 |
| **Adjustments** | | | | | |
| Fair market value adjustment – TECO Energy acquisition (5) | | | | $ **8** | $ 22 |
| Debt issuance costs | | | | **(119)** | (113) |
| Classification as liabilities held for sale (6) | | | | **(516)** | – |
| Amount due within one year (7) | | | | **(501)** | (1,119) |
| | | | | $ **(1,128)** | $ (1,210) |
| **Long-Term Debt** | | | | $ **13,679** | $ 14,292 |

(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.
(6) Emera Maine's assets and liabilities are classified as held for sale. Refer to note 4 for further details.
(7) Excludes Emera Maine amounts which are classified as current liabilities associated with assets held for sale.

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 | | 2019 | | 2018 |
|---|---|---|---|---|---|
| Emera – revolving credit facility (1) | June 2024 | $ | **900** | $ | 900 |
| NSPI – revolving credit facility (1) | October 2024 | | **600** | | 600 |
| Emera Maine – revolving credit facility | February 2023 | | **104** | | 109 |
| BLPC – revolving credit facility | 2020–2032 | | **25** | | 26 |
| Total | | | **1,629** | | 1,635 |
| Less: | | | | | |
| Borrowings under credit facilities | | | **771** | | 899 |
| Letters of credit issued inside credit facilities | | | **65** | | 77 |
| Use of available facilities | | | **836** | | 976 |
| Available capacity under existing agreements | | $ | **793** | $ | 659 |

(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, 2019 |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.59 : 1 |

## RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

### Florida Electric Utilities

On July 24, 2019, TEC completed a $300 million USD 30-year senior notes issuance. The notes bear interest at a rate of 3.625 per cent and have a maturity date of June 15, 2050.

### Canadian Electric Utilities

On November 25, 2019, NSPI amended its operating credit facility to extend the maturity from October 2023 to October 2024. All other terms of the agreement are the same.

On August 2, 2019, NSPI repaid a $95 million debenture upon maturity. The debenture was repaid using its operating credit facility.

On April 4, 2019, NSPI completed a $400 million Series AB 30-year medium term notes issuance. The notes bear interest at a rate of 3.57 per cent and have a maturity date of April 5, 2049.

### Gas Utilities and Infrastructure

On December 19, 2019, NMGC completed a $80 million USD 30-year unsecured note issuance. The notes bear interest at a rate of 3.72 per cent and have a maturity date of December 15, 2049.

On December 19, 2019, NMGC completed a $15 million USD 15-year unsecured note issuance. The notes bear interest at a rate of 3.24 per cent and have a maturity date of December 15, 2034.

On July 31, 2019, New Mexico Gas Intermediate ("NMGI") repaid a $50 million USD note upon maturity. The note was repaid using cash on hand.

On May 17, 2019, Emera Brunswick Pipeline amended the maturity date of its $250 million Credit Agreement from February 2022 to May 2023. There were no other material changes in commercial terms.

### Other Electric Utilities

On December 10, 2019, Emera Maine completed a securities issuance for $60 million USD senior unsecured notes. The 30-year notes bear interest at a rate of 3.79 per cent and will mature on December 10, 2049.

### Other

On December 2, 2019, Emera's Series G $225 million 4.83 per cent medium-term notes matured and were repaid. The notes were repaid using existing credit facilities.

On June 14, 2019, Emera Finance repaid a $500 million USD note upon maturity. The note was repaid using proceeds from the sale of the NEGG facilities.

On June 13, 2019, Emera extended the maturity date of its $900 million revolving credit facility from June 2020 to June 2024. There were no other significant changes in commercial terms from the prior agreement.

### 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 | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Emera | $ – | $ – | $ – | $ 500 | $ 437 | $ 1,559 | $ 2,496 |
| Emera US Finance LP | – | 974 | – | – | – | 2,598 | 3,572 |
| TECO Finance | 390 | – | – | – | – | – | 390 |
| Tampa Electric | – | 301 | 292 | – | – | 2,741 | 3,334 |
| PGS | – | 61 | 32 | – | – | 344 | 437 |
| NMGC | – | – | – | – | 195 | – | 195 |
| NMGI | – | 260 | – | – | – | 214 | 474 |
| NSPI | – | – | – | – | 308 | 2,365 | 2,673 |
| Emera Maine (1) | 49 | – | 107 | 11 | – | 351 | 518 |
| EBP | – | – | – | 248 | – | – | 248 |
| ECI | 111 | 69 | 81 | 72 | 47 | 90 | 470 |
| Total | $ 550 | $ 1,665 | $ 512 | $ 831 | $ 987 | $ 10,262 | $ 14,807 |

(1) Classified as held for sale.

## 25. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to 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 | **2019** | 2018 |
|---|---|---|
| Balance, January 1 | **$ 205** | $ 172 |
| Additions (1) | **–** | 25 |
| Liabilities settled (1) | **(25)** | (2) |
| Accretion included in depreciation expense | **7** | 6 |
| Other | **3** | (1) |
| Change in foreign exchange rate | **(5)** | 5 |
| Balance, December 31 | **$ 185** | $ 205 |

(1) Tampa Electric produces ash and other by-products, collectively known as CCR's, at its Big Bend and Polk power stations. The increase in ARO in 2018 was to achieve compliance with the US Environmental Protection Agency's CCR rule due to the closure of a CCR management facility that began in 2018. The closure was completed in 2019.

# 26. COMMITMENTS AND CONTINGENCIES

## A. COMMITMENTS

As at December 31, 2019, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

| millions of Canadian dollars | 2020 | 2021 | 2022 | 2023 | 2024 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Purchased power (1) (2) | $ 210 | $ 233 | $ 237 | $ 246 | $ 249 | $ 2,228 | $ 3,403 |
| Transportation (3) | 514 | 398 | 340 | 281 | 264 | 2,720 | 4,517 |
| Capital projects (4) | 411 | 109 | 103 | 86 | – | – | 709 |
| Fuel, gas supply and storage | 466 | 133 | 22 | 1 | – | – | 622 |
| Long-term service agreements (5) (6) | 52 | 37 | 36 | 27 | 26 | 100 | 278 |
| Equity investment commitments (7) | 240 | – | – | – | – | – | 240 |
| Leases and other (8) | 19 | 19 | 18 | 17 | 8 | 118 | 199 |
| Demand side management | 38 | 41 | 43 | – | – | – | 122 |
| | $ 1,950 | $ 970 | $ 799 | $ 658 | $ 547 | $ 5,166 | $ 10,090 |

As noted below, contractual obligations at December 31, 2019 include amounts related to Emera Maine. On completion of the sale of Emera Maine, all of the remaining future contractual obligations will be transferred to the buyer. Refer to note 4 for additional information.

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(2) Includes $520 million related to Emera Maine ($13 million in 2020; $23 million in 2021; $27 million in 2022; $31 million in 2023; $31 million in 2024 and $395 million thereafter).
(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(4) Includes $345 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 $44 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($19 million in 2020; $9 million in 2021; $8 million in 2022; and $8 million in 2023).
(7) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(8) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years from its January 15, 2018 in-service date. The UARB approved payment for 2019 was $111 million subject to a $10 million holdback and as at December 31, 2019, $101 million has been paid. The UARB approved payment for 2020 is $145 million, subject to a holdback of up to $10 million. As part of NSPI's 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and estimated amounts of $164 million and $162 million for 2021 and 2022, respectively. These estimated amounts are subject to review and approval by the UARB. The timing and amounts payable to NSPML for the remainder of the 37-year commitment period are dependent on regulatory filings with the UARB.

Emera has committed to obtain certain transmission rights for Nalcor Energy, if requested, to enable them to transmit energy which is not otherwise used in Newfoundland or Nova Scotia. This energy would be transmitted from Nova Scotia to New England energy markets beginning at first commercial power of the Muskrat Falls hydroelectric generating facility and related transmission assets when Nalcor commences delivery of the NS Block, and continuing for 50 years. As transmission rights are contracted, Emera includes the obligations within "Leases and other" in the above table.

## B. LEGAL PROCEEDINGS

### 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 was fully briefed. A hearing was held in March 2019 and a decision is expected from the tribunal in 2020. In addition, TGH sued Guatemala in Washington, D.C. court to enforce the $21 million USD owing. Guatemala's motion to dismiss the enforcement action was denied. On October 1, 2019, the court granted TGH's motion for summary judgment which will allow TGH to seek collection of the award plus interest when the order is final. Guatemala has appealed that decision. 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, 2019, TEC has estimated its financial liability to be $27 million ($21 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 return on equity ("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 any of the four pending complaints due to uncertainty.

On November 21, 2019, the FERC approved an order affecting transmission ROEs in the Midcontinent ISO region (MISO) that alters the Commission's methodology for analyzing the base return on equity component of a jurisdictional public utility's rates. The methodology applied in the MISO case may be applied by the FERC in the pending ISO NE cases. No date for a decision has been made yet, but the FERC is expected to rule on these three outstanding ISO-NE cases in 2020. Additionally, both the MISO case, and a decision in the ISO-NE cases, will be subject to further appeal rights and, if appealed, a final decision would be unlikely to occur before Q4 2020. Therefore, no change in Emera Maine's accrual related to ROE complaints has been made as a result of the MISO decision.

### 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 13 and note 14.

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 may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. 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, and on net income earned outside of Canada. 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 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, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other sever weather events. 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 guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2019:

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 $82 million USD (December 31, 2018 – $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 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 2020 and is renewed annually. The amount committed as at December 31, 2019 was $52 million (December 31, 2018 – $49 million).

### Collaborative Arrangements

For the years ended December 31, 2019 and 2018, 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 2019, NSPI recognized $19 million net expense (2018 – $19 million) in "Regulated fuel for generation and purchased power" and $3 million (2018 – $2 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.

| | | | **December 31, 2019** | | December 31, 2018 | |
|---|---|---|---|---|---|---|
| | Annual Dividend per Share | Redemption Price per Share | **Issued and Outstanding** | **Net Proceeds** | Issued and Outstanding | Net Proceeds |
| Series A | $ 0.6388 | $ 25.00 | **3,864,636** | **$ 95** | 3,864,636 | $ 95 |
| Series B | Floating | $ 25.00 | **2,135,364** | **$ 52** | 2,135,364 | $ 52 |
| Series C | $ 1.1802 | $ 25.00 | **10,000,000** | **$ 245** | 10,000,000 | $ 245 |
| Series E | $ 1.1250 | $ 25.75 | **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** | 12,000,000 | $ 295 |
| Total | | | **41,000,000** | **$ 1,004** | 41,000,000 | $ 1,004 |

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 (6) | 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 (7) | 4.500 | 1.1250 | | | 25.75 | |

(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, 2023, 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) On January 7, 2020, Emera announced it would not redeem the 8,000,000 Cumulative Rate Reset First Preferred Shares, Series F Shares. The holders of the Series F Shares have the right, at their option, to convert all or any of their Series F Shares, on a one-for-one basis, into Cumulative Floating Rate First Preferred Shares, Series G of the Company on February 15, 2020, or to continue to hold their Series F Shares. On February 6, 2020, Emera announced that, after having taken into account all conversion notices received from holders, no First Preferred Shares, Series F Shares would be converted into Cumulative Floating Rate First Preferred Shares, Series G Shares.
(7) First Preferred Shares, Series E are redeemable at $25.75 to August 15, 2020, 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

| As at<br>millions of Canadian dollars | December 31<br>2019 | December 31<br>2018 |
|---|---|---|
| Preferred shares of GBPC | $ 14 | $ 19 |
| Domlec | 21 | 22 |
| | $ 35 | $ 41 |

### PREFERRED SHARES OF GBPC:

**Authorized:**

10,000 non-voting cumulative redeemable variable perpetual preferred shares.

| | 2019 | | 2018 | |
|---|---|---|---|---|
| **Issued and outstanding:** | number of shares | millions of dollars | number of shares | millions of dollars |
| Outstanding as at December 31 | 10,000 | $ 14 | 20,000 | $ 19 |

### GBPC NON-VOTING CUMULATIVE VARIABLE PERPETUAL PREFERRED STOCK:

In June 2019, GBPC redeemed all outstanding preferred shares, replacing them with $10 million USD debt at 4 per cent and $10 million USD preferred shares at 6 per cent. The new preferred shares are redeemable by GBPC after June 17, 2021, at $1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually, with the first payment scheduled for January 2020.

The Preferred Shares rank behind GBPC's current and future secured and unsecured debt 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 | 2019 | 2018 |
| Changes in non-cash working capital: | | |
| Inventory | $ (19) | $ (44) |
| Receivables and other current assets | 154 | (144) |
| Accounts payable | (137) | 59 |
| Other current liabilities | (71) | 13 |
| Total non-cash working capital | $ (73) | $ (116) |
| **Supplemental disclosure of cash paid (received):** | | |
| Interest | $ 750 | $ 696 |
| Income taxes | $ (107) | $ 33 |
| **Supplemental disclosure of non-cash activities:** | | |
| Common share dividends reinvested | $ 187 | $ 181 |
| Increase in accrued capital expenditures | $ 33 | $ 50 |
| 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. As of December 31, 2019, the plan allows employees to 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 the 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, 2019, Emera is in compliance with this requirement.

Compensation cost for shares issued by Emera for the year ended December 31, 2019 under the Employee Common Share Purchase Plan was $1 million (2018 – $1 million) and is included in "OM&G" on the Consolidated Statements of Income.

In November 2019, Emera's Board of Directors approved changes to the ECSPP which are expected to be effective in 2020. These changes include increasing the maximum employee cash contribution to $20,000 and changing the Company's matching contribution to 20 per cent of the employees' contributions. In addition, the Company match on dividends that exists within the current ECSPP plan will be discontinued.

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 and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends. In 2019, the discount was changed from 5 per cent to 2 per cent effective with the dividend payment of August 15, 2019.

## 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, 2019, 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 31:

| | 2019 | 2018 |
|---|---|---|
| Weighted average fair value per option | **$ 2.41** | $ 1.70 |
| Expected term (1) | **6 years** | 6 years |
| Risk-free interest rate (2) | **1.82%** | 2.13% |
| Expected dividend yield (3) | **5.10%** | 5.69% |
| Expected volatility (4) | **14.32%** | 13.71% |

(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 2019:

| | 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, 2018 | 4,225,575 | $ 39.56 | 1,679,325 | $ 2.22 |
| Granted | 651,400 | 46.39 | 651,400 | 2.41 |
| Exercised | (2,568,625) | 37.90 | N/A | N/A |
| Vested | N/A | N/A | (759,900) | 2.37 |
| Forfeited | (21,800) | 46.39 | (21,800) | 2.41 |
| Expired | N/A | N/A | N/A | N/A |
| **Options outstanding December 31, 2019** | **2,286,550** | **$ 43.31** | **1,549,025** | **$ 2.22** |
| **Options exercisable December 31, 2019** (2) (3) | **737,525** | **$ 41.43** | | |

(1) As at December 31, 2019, there was $2 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 2.4 years (2018 – $2 million, 2.2 years).
(2) As at December 31, 2019, the weighted average remaining term of vested options was 5.5 years with an aggregate intrinsic value of $11 million (2018 – 5.1 years, $18 million).
(3) As at December 31, 2019, the fair value of options that vested in the year was $2 million (2018 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2019 was $1 million (2018 – $1 million), which is included in "OM&G" on the Consolidated Statements of Income.

As at December 31, 2019, cash received from option exercises was $97 million (2018 – $1 million). The total intrinsic value of options exercised for the year ended December 31, 2019 was $32 million (2018 – $1 million). The range of exercise prices for the options outstanding as at December 31, 2019 was $32.06 to $46.39 (2018 – $21.99 to $46.19).

## SHARE UNIT PLANS

The Company has DSU, PSU and RSU 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. 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 Emera's closing common share price on the date DSUs are redeemed.

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, 2019 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, 2018 | 837,109 | $ 29.54 | 563,521 | $ 37.07 |
| Granted including DRIP | 120,098 | 39.05 | 104,293 | 42.25 |
| Exercised | (252,610) | 19.68 | (136,360) | 29.76 |
| **Outstanding and exercisable as at December 31, 2019** | **704,597** | **$ 34.69** | **531,454** | **$ 39.96** |

Compensation cost recognized for employee and director DSU for the year ended December 31, 2019 was $24 million (2018 – ($2 million)). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2019 were $7 million (2018 – $1 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2019 for employees was $40 million (2018 – $37 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2019 for directors was $30 million (2018 – $25 million).

### Performance Share Unit Plan

Under the PSU plan, certain 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 the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. 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 may be pro-rated in certain departure scenarios.

A summary of the activity related to employee PSUs for the year ended December 31, 2019 is presented in the following table:

| | Employee PSU | Weighted Average Grant Date Fair Value | Aggregate Intrinsic Value |
|---|---|---|---|
| Outstanding as at December 31, 2018 | 1,127,114 | $ 46.02 | $ 56.9 |
| Granted including DRIP | 545,008 | 43.15 | |
| Exercised | (140,754) | 43.00 | |
| Forfeited | (150,268) | 44.41 | |
| **Outstanding as at December 31, 2019** | **1,381,100** | **$ 45.37** | **$ 88.1** |

Compensation cost recognized for the PSU plan for the year ended December 31, 2019 was $34 million (2018 – $14 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2019 were $9 million (2018 – $4 million).

### Restricted Share Unit Plan

In November 2019, a new RSU plan was approved by Emera's Board of Directors, with grants to begin in 2020. Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping cycles, resulting in a cash payment. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs 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 may be pro-rated in certain departure scenarios.

## 31. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any Variable Interest Entities ("VIE") or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method.

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. When the critical milestones were achieved, Nalcor Energy was deemed the primary beneficiary of the asset for financial reporting purposes as it has 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 Self-Insurance Fund ("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, 2019** | | December 31, 2018 | |
|---|---|---|---|---|
| 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) | **$ 554** | **$ 23** | $ 545 | $ 51 |

## 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 14, 2020, 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, 2019 | | | | | | |
| Operating revenues | $ – | $ – | $ 4,125 | $ 2,029 | $ (43) | **$ 6,111** |
| Operating expenses | 31 | – | 3,084 | 1,695 | (42) | **4,768** |
| Income (loss) from equity investments and subsidiaries | 753 | – | 2 | 151 | (752) | **154** |
| Other income (expenses), net | 21 | – | 22 | (11) | (20) | **12** |
| Interest expense, net (1) | 75 | (40) | 481 | 222 | – | **738** |
| **Income (loss) before provision for income taxes** | 668 | 40 | 584 | 252 | (773) | **771** |
| Income tax expense (recovery) | (40) | 11 | 60 | 30 | – | **61** |
| **Net income (loss)** | 708 | 29 | 524 | 222 | (773) | **710** |
| Non-controlling interest in subsidiaries | – | – | – | – | 2 | **2** |
| Preferred stock dividends | 45 | – | 19 | 3 | (22) | **45** |
| **Net income (loss) attributable to common shareholders** | $ 663 | $ 29 | $ 505 | $ 219 | $ (753) | **$ 663** |
| **Comprehensive income (loss) of Emera Incorporated** | $ 465 | $ 14 | $ 102 | $ 205 | $ (321) | **$ 465** |

| 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 |

(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, 2019 | | | | | | |
| **Assets** | | | | | | |
| **Current assets** | $ 96 | $ 27 | $ 1,486 | $ 1,171 | $ (294) | **$ 2,486** |
| **Property, plant and equipment** | 23 | - | 13,099 | 5,040 | 5 | **18,167** |
| **Other assets** | | | | | | |
| Regulatory assets | - | - | 519 | 912 | - | **1,431** |
| Goodwill | 3 | - | 5,762 | 70 | - | **5,835** |
| Other long-term assets | 11,994 | 3,856 | 1,739 | 3,289 | (16,955) | **3,923** |
| Total other assets | 11,997 | 3,856 | 8,020 | 4,271 | (16,955) | **11,189** |
| **Total assets** | $ 12,116 | $ 3,883 | $ 22,605 | $ 10,482 | $ (17,244) | **$ 31,842** |
| **Liabilities and Equity** | | | | | | |
| **Current liabilities** | $ 542 | $ 12 | $ 3,699 | $ 992 | $ (1,079) | **$ 4,166** |
| **Long-term liabilities** | | | | | | |
| Long-term debt | 2,978 | 3,534 | 8,829 | 4,547 | (6,209) | **13,679** |
| Deferred income taxes | - | 3 | 515 | 767 | - | **1,285** |
| Regulatory liabilities | - | - | 1,793 | 93 | - | **1,886** |
| Other long-term liabilities | 38 | - | 1,697 | 511 | (21) | **2,225** |
| Total long-term liabilities | 3,016 | 3,537 | 12,834 | 5,918 | (6,230) | **19,075** |
| **Total Emera Incorporated equity** | 8,558 | 334 | 6,072 | 3,551 | (9,949) | **8,566** |
| Non-controlling interest in subsidiaries | - | - | - | 21 | 14 | **35** |
| Total equity | 8,558 | 334 | 6,072 | 3,572 | (9,935) | **8,601** |
| **Total liabilities and equity** | $ 12,116 | $ 3,883 | $ 22,605 | $ 10,482 | $ (17,244) | **$ 31,842** |
| 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 |

**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, 2019 | | | | | | |
| **Net cash provided by (used in) operating activities** | $ 133 | $ 33 | $ 1,100 | $ 279 | $ (20) | **$ 1,525** |
| **Investing activities** | | | | | | |
| Additions to property, plant and equipment | (2) | - | (1,973) | (520) | - | **(2,495)** |
| Net purchase of investments subject to significant influence | - | - | (3) | - | - | **(3)** |
| Proceeds on disposal of assets | - | - | 818 | 57 | - | **875** |
| Other investing activities | (402) | 595 | 774 | (1) | (960) | **6** |
| **Net cash provided by (used in) investing activities** | (404) | 595 | (384) | (464) | (960) | **(1,617)** |
| **Financing activities** | | | | | | |
| Change in short-term debt, net | 399 | - | (9) | 23 | - | **413** |
| Proceeds from long-term debt | - | - | (6) | 552 | 520 | **1,066** |
| Retirement of long-term debt | (225) | (664) | (65) | (166) | 17 | **(1,103)** |
| Net borrowings (repayments) under committed credit facilities | 146 | - | (11) | (225) | (28) | **(118)** |
| Issuance of common and preferred stock | 203 | - | (620) | 58 | 562 | **203** |
| Dividends paid | (423) | - | (19) | (138) | 157 | **(423)** |
| Other financing activities | (1) | - | 138 | 87 | (248) | **(24)** |
| **Net cash provided by (used in) financing activities** | 99 | (664) | (592) | 191 | 980 | **14** |
| Effect of exchange rate changes on cash, cash equivalents, restricted cash and assets held for sale | 147 | (3) | (141) | (23) | - | **(20)** |
| **Net increase (decrease) in cash, cash equivalents, restricted cash and assets held for sale** | (25) | (39) | (17) | (17) | - | **(98)** |
| Cash, cash equivalents and restricted cash, beginning of year | 20 | 58 | 104 | 190 | - | **372** |
| Cash, cash equivalents, restricted cash and assets held for sale, end of year | $ (5) | $ 19 | $ 87 | $ 173 | $ – | **$ 274** |

**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, 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 LEADERSHIP AND BOARD

As of March 31, 2020

## EMERA LEADERSHIP

**Scott Balfour**
President and
Chief Executive Officer,
Emera Inc.

**Rob Bennett**
President and Chief
Executive Officer,
Emera Technologies LLC

**Greg Blunden**
Chief Financial Officer,
Emera Inc.

**Robert Hanf** (1)
Executive Vice President,
Stakeholder Relations
and Regulatory Affairs,
Emera Inc.

**Chris Heck**
Chief Digital Officer,
Emera Inc.

**Mike Herrin** (2)
President and Chief
Operating Officer,
Emera Maine

**Karen Hutt**
Executive Vice President,
Business Development
and Strategy,
Emera Inc.

**Rick Janega**
Chief Operating Officer,
Electric Utilities, Canada,
US Northeast and Caribbean,
Emera Inc.

President and Chief Executive
Officer, Emera Newfoundland
and Labrador

**Bruce Marchand**
Chief Legal and Compliance
Officer,
Emera Inc.

**Dan Muldoon**
Executive Vice President,
Project Development
and Operations Support,
Emera Inc.

**Wayne O'Connor**
President and
Chief Executive Officer,
Nova Scotia Power

**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

## BOARD OF DIRECTORS

**Jackie Sheppard**
Chair, Emera Inc.

Former Executive
Vice President,
Corporate & Legal Affairs,
Talisman Energy Inc.,
Calgary, Alberta

**Scott Balfour**
President and
Chief Executive Officer,
Emera Inc.,
Halifax, Nova Scotia

**James Bertram**
Chair of the Board,
Keyera Corp.,
Calgary, Alberta

**Sylvia Chrominska**
Former Group Head,
Global Human Resources
and Communications,
The Bank of Nova Scotia,
Toronto, Ontario

**Henry Demone**
Former Chairman,
High Liner Foods,
Lunenburg, Nova Scotia

**Kent Harvey**
Former Chief Financial
Officer,
PG&E Corporation,
New York, New York

**Lynn Loewen, FCPA, FCA**
Former 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.,
Toronto, Ontario

(1) Robert Hanf retired from Emera effective March 31, 2020.
(2) Effective until March 24, 2020 when the sale of Emera Maine closed.

# 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 or 1.888.450.0507

Information regarding Company news and initiatives, including our 2019 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

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Senior Director, Capital Markets
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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: 242,478,188 (as of December 31, 2019)

## DIVIDENDS PAID IN 2019

Emera Inc. paid Common Share dividends of $0.5875 per Common Share in Q1, Q2 and Q3 and $0.6125 in Q4, for an effective annual Common Share dividend rate of $2.3750 per Common Share.

## DIVIDEND PAYMENTS IN 2020

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 $0.6125, a Series A First Preferred Share dividend of $0.1597, a Series B First Preferred Share dividend of $0.2190, 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 14, 2020.

## 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. In 2019, the discount was changed from five per cent to two per cent and was effective with the dividend payment of August 15, 2019.

## 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 2020. Year-end results for 2019 were released in February 2020.

Emera

www.emera.com