Emera

2020 ANNUAL REPORT

2020 Financial Highlights

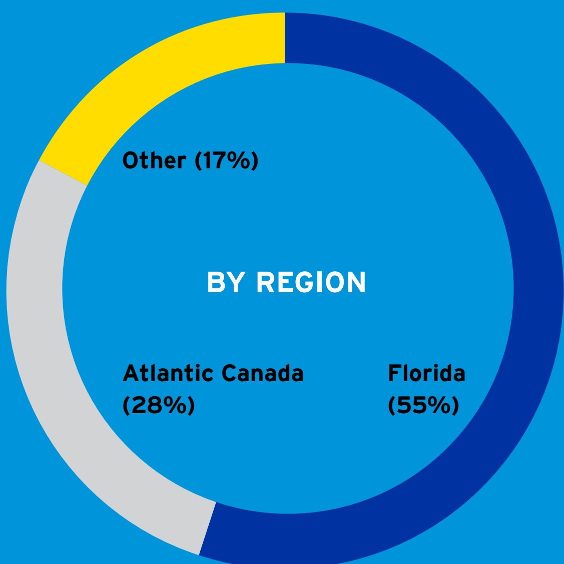
10%
annualized total shareholder return over the last five years

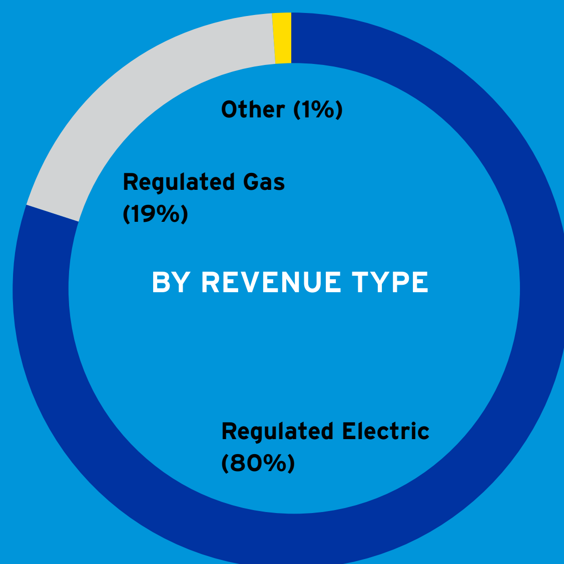
4%
increase in common share dividends paid, to $2.48 in 2020 from $2.38 in 2019

13%
growth in regulated earnings, net of corporate costs, from 2019 to 2020

95%+
of earnings derived from regulated investments

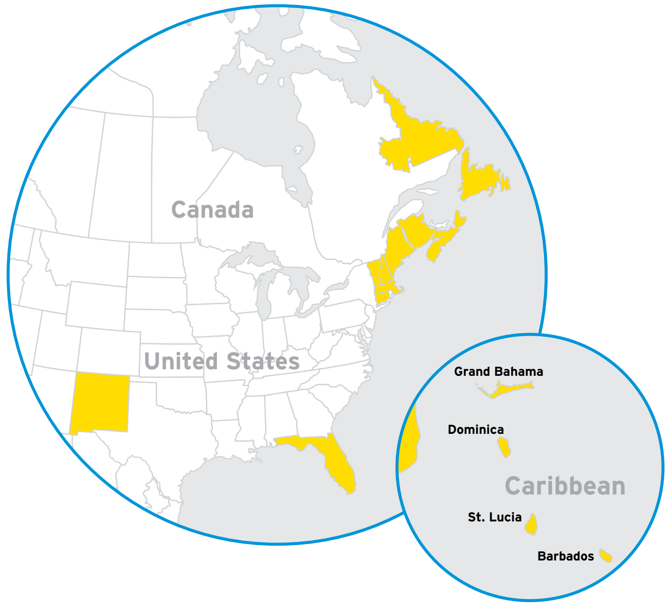
ADJUSTED REVENUE*
For the year ended December 31, 2020





*Adjusted revenue is a non-GAAP measure which excludes mark-to-market adjustments.
Data is as of December 31, 2020, unless otherwise indicated.

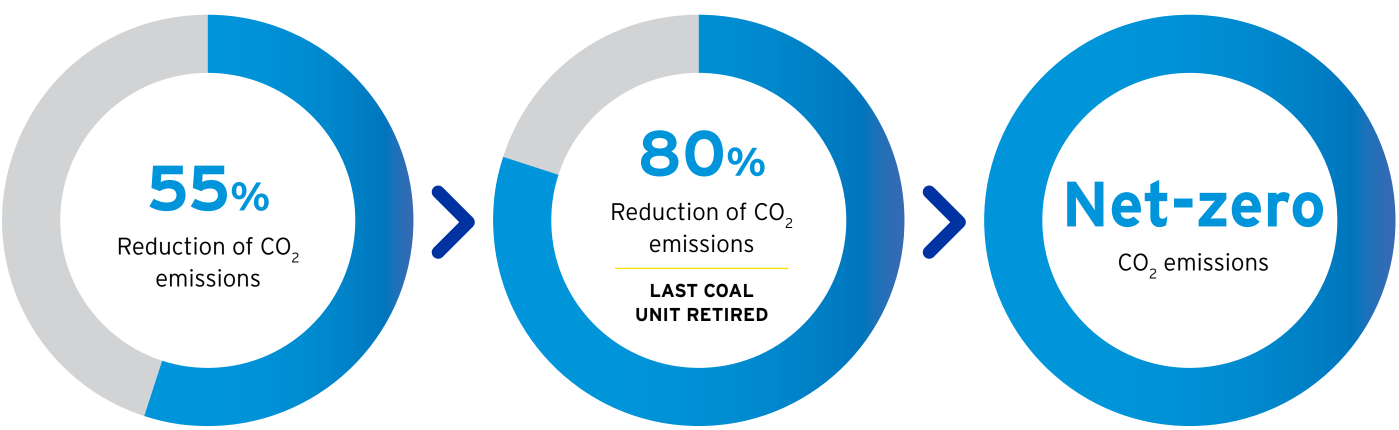
We're a team of experts focused on safely delivering cleaner, affordable and reliable energy to our over 2.5 million customers in Canada, the US and the Caribbean. Our Environmental, Social and Governance (ESG) commitments are core to our strategy and our culture. We're leading the way to a cleaner energy future with clear climate goals and a vision to achieve net-zero carbon emissions by 2050. We primarily invest in regulated electric and gas utilities, driving predictable returns and steady growth for our investors, enabling us to reinvest in our teams, our companies and communities.



OUR CLIMATE COMMITMENT

Since 2005, we've reduced CO_2 emissions by **39%** and coal use by **68%**	By 2023, we'll reduce our coal use by at least **80%**

2025 GOAL | **2040 GOALS** | **2050 VISION**



Why Invest in Emera

With our proven strategy and portfolio of high-quality regulated utilities, Emera is well-positioned to continue to deliver for our customers while also providing our shareholders with long-term growth in earnings, cash flow and dividends.

EXPERT TEAMS
We're a team of experts leading the way to a cleaner energy future as we work toward our 2050 Net-Zero Vision.

DELIVERING FOR OUR CUSTOMERS
Every day, we're safely delivering cleaner, affordable and reliable energy for our customers.

DRIVING GROWTH AND REINVESTMENT
Delivering for our customers drives predictable returns and steady growth for our investors, enabling us to reinvest in our teams, companies, and communities.

Our ESG commitments are core to our strategy and our culture, and they drive our growth and innovation at Emera. We're investing in cleaner sources of energy and in transmission assets to bring that energy where it's needed. We're also investing in reliability, system expansion and modernization, while never losing sight of cost and affordability for customers. We're building on our strong decarbonization track record with clear, future-focused goals, including a CO_2 reduction of 80 per cent by 2040 compared to 2005 levels, and our vision to achieve net-zero carbon emissions by 2050.

FINANCIAL

4-5%
dividend growth target through to 2022

$7.4B-$8.6B
capital investment plan through 2023

7.5-8.5%
rate base growth through 2023

OPERATIONAL

1,262 MW
installed renewable capacity

1.4M
smart meters to be installed by 2022; 1M+ already complete

1,250 MW
solar capacity at Tampa Electric by 2023; 630MW installed since 2016

ENVIRONMENTAL

39%
reduction in CO_2 emissions from 2005[1]

68%
reduction in our use of coal in generation from 2005

60%
of capital plan to 2023 invested in decarbonization and reliability

COMMUNITY

$16M
invested in our communities

40,470 HOURS
volunteered by Emera employees

$5M
Inclusion & Diversity Community Fund established

SAFETY AND EMPLOYEES

25%
reduction in OSHA injury rate

41%
of senior leaders at Emera Inc. are women; 34% across Emera[2]

32%
reduction in Lost Time Injury Rate

237
Proactive Rate (PAIR) – the number of proactive safety reports per 100 employees

Top 100 Employer
in Canada for 3rd consecutive year

GOVERNANCE

36%
of Director Nominees are women, including the Chair

99%
shareholder support for 2020 Say on Pay vote

100%
of employees completed annual Code of Conduct training

1 Up from 36% in 2019.
2 Senior leaders includes Director level and above.

Data is as of Dec. 31, 2020, unless otherwise indicated.

Letter from the Chair and the CEO

Fellow shareholders,

Despite the extraordinary and unexpected challenges of the global COVID-19 pandemic, we are proud of what the team accomplished in 2020 for our customers, communities, and shareholders. Our ability to adapt and deliver the essential energy our customers count on, perhaps now more than ever, is a testament to the strength and resiliency of our teams and our strategy.

COVID RESPONSE

Our commitment to health and safety is core to our pandemic planning and our continued response to COVID-19. Last year, our teams adapted quickly to add new protocols and procedures to continue to safely deliver the cleaner, affordable and reliable energy our customers count on.

Our teams also supported our customers and communities through customer relief programs and community investments to help those most impacted by the pandemic. Across Emera's operating companies, we contributed over $6 million to organizations providing critical aid, including assistance with energy costs, food, shelter and mental health support.

FINANCIAL RESULTS

We delivered solid financial results in 2020. Our annual adjusted earnings per share (EPS) were in line with our expectations and grew by three per cent to $2.68. It's notable that the asset sales we completed over the past two years distort the actual year-over-year comparison of the performance of our business. If we adjust our EPS for the operating earnings impact of asset sales, our 2020 results were 15 per cent higher than those in 2019, principally driven by the 13 per cent year-over-year earnings growth from the continuing portion of our portfolio of regulated businesses.

The strong performance of our regulated utilities supported the four per cent increase to our dividend, keeping our commitment to providing predictable, sustainable and growing value to our investors. We continue to target 4–5 per cent dividend growth through to 2022.

We also strengthened our balance sheet – completing our asset sale program with the sale of Emera Maine in the first quarter, as well as by retiring $390 million of holding company debt and raising $490 million of common equity. We also solidified our future earnings and cash flow growth and quality with the rate case settlements secured by Peoples Gas and New Mexico Gas.

Scott Balfour
President and Chief Executive Officer,
Emera Inc.

Jackie Sheppard
Chair, Emera Inc.
Board of Directors

Photos: (Left) A technician installing solar panels at Big Bend as part of the 630MW of solar we've put into service at Tampa Electric since 2016. Another 600MW will be complete by 2023. (Centre) A member of the Nova Scotia Power team at the Digby Neck Wind Farm. At 18 per cent, NSP has one of the highest integrations of wind in North America. (Right) A People's Gas employee performs maintenance at a transmission gate station in Florida. Natural gas is an important source of cleaner energy as we focus on eliminating coal by 2040.

In the capital markets, regulated utility stocks, including Emera, did not perform as well as we might have expected given the stable financial performance within an environment of lower interest rates and economic uncertainty for much of the year – typically conditions when regulated utility stocks would outperform. Emera and our peers underperformed as investors preferred other sectors. As a result, while our total shareholder return for the year was consistent with our regulated utility peers in Canada and the US, it was lower than both the TSX Capped Utilities Index and TSX Composite. Despite the share performance of our industry in 2020, Emera's longer-term total shareholder return continued to provide consistent and competitive value to our investors, delivering 10 per cent returns over the past three, five and ten years.

PROVEN STRATEGY

Our strategy is designed to deliver for our customers and shareholders today and prepare for an energy future that is being shaped by the customer-driven trends of decarbonization, decentralization and digitalization.

For over 15 years, we've been focused on safely delivering cleaner, affordable, reliable energy for our customers. By delivering for our customers, we are driving predictable returns and steady growth for our investors, enabling us to reinvest in our teams, companies, and communities.

STRATEGY IN ACTION

Even with the challenges of the pandemic and additional protocols in place, we continued to advance our strategy and our capital program, executing $2.7 billion in capital in 2020, more than any other year in our history. Our large capital projects remained on time and on budget.

- As Florida's top producer of solar energy per customer, Tampa Electric completed construction of the final phase of its first 600MW of solar, putting six million solar panels into service over the last three years. And we started work on another 600MW to be put into service in 2023. Within two years, nearly 14 per cent of Tampa Electric's energy will come from the sun – enough to power more than 200,000 homes.
- The team at Tampa Electric made significant progress on the $850M USD modernization of Big Bend facility, and remains on budget and on track for putting the gas generators into service in "simple cycle" mode at the end of this year, further reducing our use of coal. When complete in 2023, this project will have state-of-the-art, highly efficient, combined-cycle natural gas units, capable of producing 1,090MW of electricity.

We recently announced our Climate Commitment – a set of clear decarbonization goals and our vision to achieve net-zero CO_2 emissions by

2050

"By delivering for our customers, we are driving predictable returns and steady growth for our investors, enabling us to reinvest in our teams, companies, and communities."

- We continued our deployment of next generation automatic meter infrastructure (smart meters) to electric utility customers in Florida, Barbados and Nova Scotia with over a million now in service. Smart meters provide our customers with greater access to information about energy use and they will eventually help us with faster restoration times. Across Emera, we will install roughly 1.4 million smart meters by 2022.
- The team at New Mexico Gas completed the Santa Fe Loop project. This was the largest pipeline expansion in the history of the company, significantly increasing capacity and reliability for customers.
- We advanced the Clean Energy Bridge project in Barbados, a new 33MW generation facility that will serve as critical generation capacity, delivering affordable and reliable energy for customers, as we continue to champion and build renewables and transition to a 100 per cent clean energy future in Barbados. Construction is expected to be complete later this year.
- We launched Emera Technologies' BlockEnergy microgrid solution, an innovative, utility-owned platform that integrates rooftop solar, energy storage and smart controls. BlockEnergy creates independent clean energy networks and maximizes reliability by also being fully connected to the power grid. BlockEnergy was developed in partnership with Sandia National Labs and has been successfully demonstrated and tested at the US Air Force Base in Albuquerque, New Mexico. BlockEnergy is now advancing to a full-scaled pilot as it is currently being installed for 37 homes in a residential community under construction in the Tampa, Florida area.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

Our Environmental, Social and Governance (ESG) commitments have been core to our strategy and our culture for more than 15 years. Last year, in addition to advancing our ESG commitments, we also enhanced our ESG reporting with the addition of two new disclosure frameworks. We also reinforced our ESG governance by appointing executive oversight of ESG and establishing a Sustainability Management Committee to oversee our ESG risk management, disclosures and focus areas.

We will be releasing our 2020 Sustainability Report later this year. Previous reports are available on our **website**.

Decarbonization and 2050 Net-Zero Vision

Decarbonization is central to our strategy and a key driver of our growth. For more than 15 years we've been working to reduce CO_2 emissions from across our operations, and in 2020 we achieved a 39 per cent reduction over 2005 levels. We recently announced our Climate Commitment – building on our strong decarbonization track record by setting clear future-focused carbon reduction goals and a vision to achieve net-zero carbon emissions by 2050. With existing technologies and resources and the benefit of supportive regulatory decisions, we plan and expect to achieve the following goals compared to corresponding 2005 levels:

- A 55 per cent reduction in carbon emissions by 2025.
- An 80 per cent reduction in coal usage by 2023 and the retirement of our last existing coal unit no later than 2040.
- At least an 80 per cent reduction in carbon emissions by 2040.

We're seeking to achieve these goals and realize our net-zero vision while staying focused on enhancing reliability, maintaining affordability, adopting emerging technologies and working constructively with policymakers, regulators, partners, investors, and our communities.

Inclusion and Diversity

We know diverse cultures and experiences make our business stronger. We are committed to providing diverse and inclusive workplaces where everyone is valued and treated with respect. We continue to execute on our multi-year Inclusion and Diversity Strategy to align best practices and drive key areas of focus and improvement. We continually assess and address pay equity gaps, conduct training for all Emera leaders and Board members, cultivate strong I&D employee networks, gather self-identification data to ensure our teams reflect the communities where we operate, integrate our commitment to diversity into our recruitment and advancement strategies and we recently established a $5 million fund to support inclusion and diversity efforts in our communities. We've made good progress, but we know there is more work to be done.

Safety

In 2020, we made good progress on our safety performance and reinforcing our strong safety culture. We implemented our company-wide safety management system and achieved the lowest Occupational Safety & Health Association (OSHA) and Lost Time Injury rates in our history. However, recent contractor fatalities serve as tragic reminders that our work in this area is never done. We're more resolved than ever to achieve an Emera where no one gets hurt.

BOARD OF DIRECTORS

Sylvia Chrominska, a valued member of our Board since 2010, is stepping down this year. Sylvia has made significant contributions to our Board, particularly as a member of the Management Resources and Compensation Committee, and as committee Chair since 2016. In this role, she provided exceptional guidance and oversight to Emera's human resources strategy and compensation practices. Thank you, Sylvia. On behalf of all of us, you will be missed.

We would also like to welcome Karen Sheriff, who joined our Board in February 2021. Karen brings cross-industry leadership experience, along with her extensive expertise in driving innovation and corporate strategy. Karen is a valuable addition to our Board.

THANK YOU

With a strong team and proven strategy, Emera is well positioned for future growth.

To the Board of Directors and the entire Emera team, thank you for your ongoing commitment to a strong and stable Emera. To our valued shareholders, thank you for your continued support.

Jackie Sheppard
Chair, Emera Inc. Board of Directors

Scott Balfour
President and Chief Executive Officer, Emera Inc.

FINANCIAL REVIEW

MANAGEMENT'S DISCUSSION & ANALYSIS

As at February 16, 2021

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 2020 relative to the same quarter in 2019; the full year of 2020 relative to 2019 and selected financial information for 2018; and its financial position as at December 31, 2020 relative to December 31, 2019. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Other Electric Utilities, Gas Utilities and Infrastructure, and Other.

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2020. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2020, 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")
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")
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

On March 24, 2020, the Company completed the sale of Emera Maine. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

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, carbon emissions reduction goals, 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 include without limitation: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; 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; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus ("COVID-19") pandemic; 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 continues to be 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 generally 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's $7.4 billion capital investment plan over the 2021-to-2023 period, and the potential for additional capital opportunities of $1.2 billion over the same period, results in a forecasted rate base growth of 7.5 per cent to 8.5 per cent through to 2023. The capital investment plan continues to include significant investments across the portfolio in renewable and cleaner generation, infrastructure modernization and customer-focused technologies. Emera's capital investment plan 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 equity capital markets through the dividend reinvestment plan and 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 through and beyond 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 investments 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, digitization, decarbonization, complex regulatory environments and decentralized generation.

Customers are looking for more choice, better control, and enhanced reliability in a time where costs of decentralized generation and storage have become more competitive in some regions. Advancing technologies are transforming the way utilities interact with their customers and generate and transmit energy. In addition, 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 all these trends. Emera's strategy is to fund investments in renewable energy 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 safely delivering cleaner, reliable, and affordable energy for its customers.

Building on its decarbonization progress over the past 15 years, Emera is continuing its efforts by establishing clear carbon reduction goals and a vision to achieve net-zero carbon emissions by 2050.

This vision is inspired by Emera's strong track record, the Company's experienced team, and a clear path to Emera's interim carbon goals. With existing technologies and resources and the benefit of supportive regulatory decisions, Emera plans and expects to achieve the following goals compared to corresponding 2005 levels:

- A 55 per cent reduction in carbon emissions by 2025.
- An 80 per cent reduction in coal usage by 2023 and the retirement of Emera's last existing coal unit no later than 2040.
- At least an 80 per cent reduction in carbon emissions by 2040.

Emera seeks to achieve these goals and realize its net-zero vision while remaining focused on maintaining affordability, enhancing reliability, adopting emerging technologies and working constructively with policymakers, regulators, partners, investors, and Emera's communities.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships.

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 gain on the sale of Emera Maine in 2020 and impairment charges.

The MTM adjustments are a result of the following:

- the MTM 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 MTM 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 MTM adjustments related to an interest rate swap in Brunswick Pipeline;
- the MTM adjustments related to equity securities held in BLPC and Emera Reinsurance, a captive reinsurance company in the Other segment; and
- the MTM adjustments related to Emera's foreign exchange cash flow hedges entered to manage foreign exchange earnings exposure.

Management believes excluding from net income the effect of these MTM 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 MTM adjustments for evaluation of performance and incentive compensation. For further detail on MTM adjustments, refer to the "Consolidated Financial Review" section and the "Financial Highlights" sections for Other Electric Utilities and Other segments.

In 2020, the Company recognized a gain on the sale of Emera Maine. Management believes excluding this from net income better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business. Refer to the "Significant Items Affecting Earnings" and "Developments" sections for further detail related to the sale of Emera Maine. While the gain on sale has been excluded from adjusted earnings, earnings for the Other Electric Utilities segment only includes earnings from Emera Maine up to the date of its sale in Q1 2020.

In 2019 and 2020, the Company recognized certain non-cash impairment charges. Management believes excluding from net income the effect of these charges better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. For further details, refer to the "Significant Items Affecting Earnings", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2020	2019	**2020**	2019	2018
Net income attributable to common shareholders	**$ 273**	$ 193	**$ 938**	$ 663	$ 710
Gain on sale, net of tax and transaction costs	**$ –**	$ –	**$ 309**	$ –	$ –
Impairment charges, net of tax	**$ –**	$ (34)	**$ (26)**	$ (34)	$ –
After-tax MTM gains (losses)	**$ 85**	$ 82	**$ (10)**	$ 76	$ 39
Adjusted net income attributable to common shareholders	**$ 188**	$ 145	**$ 665**	$ 621	$ 671
Earnings per common share – basic	**$ 1.09**	$ 0.79	**$ 3.78**	$ 2.76	$ 3.05
Adjusted earnings per common share – basic	**$ 0.75**	$ 0.60	**$ 2.68**	$ 2.59	$ 2.88

EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") is a non-GAAP financial measure used by Emera. EBITDA is 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 MTM, the gain on sale of Emera Maine and impairment charges, as 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 millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2020	2019	**2020**	2019	2018
Net income (1)	**$ 284**	$ 192	**$ 984**	$ 710	$ 747
Interest expense, net	**159**	181	**679**	738	713
Income tax expense	**57**	43	**341**	61	69
Depreciation and amortization	**217**	225	**881**	903	916
EBITDA	**717**	641	**2,885**	2,412	2,445
Gain on sale (excluding transaction costs)	**–**	–	**585**	–	–
Impairment charges	**–**	(34)	**(25)**	(34)	–
MTM gains (losses), excluding income tax and interest	**118**	118	**(18)**	107	58
Adjusted EBITDA	**$ 599**	$ 557	**$ 2,343**	$ 2,339	$ 2,387

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

CONSOLIDATED FINANCIAL REVIEW

SIGNIFICANT ITEMS AFFECTING EARNINGS

2020

TECO Guatemala Holdings ("TGH") International Arbitration and Award

On November 24, 2020, a payment was made by the Republic of Guatemala related to an investment TGH, a wholly owned subsidiary of TECO Energy, indirectly held prior to acquisition by Emera. The payment was based on an award issued by an International Centre for the Settlement of Investment Disputes ("ICSID") tribunal in 2013. The payment of $49 million ($36 million after tax or $0.15 per common share), net of legal costs was recognized in "Other Income" on the Consolidated Statements of Income. For further detail, refer to note 27 in the consolidated financial statements.

Gain on Sale of Emera Maine and Impairment Charges

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of $2.0 billion ($1.4 billion USD). A gain on sale of $585 million ($309 million after tax, or $1.26 per common share), net of transaction costs, was recognized in "Other Income" on the Consolidated Statements of Income. For further detail, refer to the "Developments" section.

As a result of the sale, earnings contribution from Emera Maine was $9 million lower in Q4 2020 than in Q4 2019 and $41 million lower for the year ended December 31, 2020.

In addition, impairment charges of $25 million ($26 million after tax) for the year ended December 31, 2020 were recognized on certain other assets.

Earnings Impact of After-Tax MTM Gains and Losses

After-tax MTM gains increased $3 million to $85 million in Q4 2020, compared to $82 million in Q4 2019. For the year ended December 31, 2020, after-tax MTM losses were $86 million more than the $76 million gain recorded in 2019. This increase was due to higher amortization of gas transportation assets in 2020, changes in existing positions and a larger reversal of MTM losses in 2019 at Emera Energy. This was partially offset by gains on foreign exchange cash flow hedges.

Earnings Impact of Q1 2019 Sale of NEGG and Bayside Facilities

Earnings contribution from Emera Energy Generation was $21 million lower for the year ended December 31, 2020 compared to 2019 due to the March 2019 sale of the New England Gas Generating ("NEGG") and Bayside generation facilities.

2019

GBPC Hurricane Dorian Restoration

In Q3 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.

In Q4 2019, Emera recognized impairment charges of $34 million, including $30 million related to GBPC's 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 in "Impairment charges" in the Consolidated Statements of Income. For further information, refer to note 22 to the consolidated financial statements.

GBPC's 2019 earnings decreased $13 million ($0.05 per common share) compared to 2018 due to reduced load as a result of the storm. 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 facilities.

CONSOLIDATED FINANCIAL HIGHLIGHTS BY BUSINESS SEGMENT

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
Adjusted Net Income	**2020**	2019	**2020**	2019	2018
Florida Electric Utility	**$ 101**	$ 80	**$ 501**	$ 419	$ 381
Canadian Electric Utilities	**57**	58	**221**	229	218
Other Electric Utilities	**8**	14	**33**	76	89
Gas Utilities and Infrastructure	**45**	51	**162**	183	136
Other	**(23)**	(58)	**(252)**	(286)	(153)
Adjusted net income attributable to common shareholders	**$ 188**	$ 145	**$ 665**	$ 621	$ 671
Gain on sale, net of tax and transaction costs	**–**	–	**309**	–	–
Impairment charges, net of tax	**–**	(34)	**(26)**	(34)	–
After-tax MTM gains (losses)	**85**	82	**(10)**	76	39
Net income attributable to common shareholders	**$ 273**	$ 193	**$ 938**	$ 663	$ 710

The following table highlights the significant changes in adjusted net income from 2019 to 2020:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Adjusted net income – 2019	**$ 145**	**$ 621**
Operating Unit Performance:		
Increased earnings at Tampa Electric in both periods due to the in-service of solar generation, higher allowance for funds used during construction ("AFUDC") earnings from the Big Bend modernization and solar projects, increased load driven by warmer weather, increased mix of residential sales related to the impact of COVID-19, customer growth, and a credit to depreciation expense as a result of a regulatory settlement	21	82
Increased earnings contribution from the Caribbean utilities in Q4 2020 due to continued recovery from Hurricane Dorian at GBPC. Year-over-year, earnings contribution decreased in 2020 due to lower sales related to the impact of COVID-19 and continued recovery from Hurricane Dorian at GBPC	3	(12)
Decreased earnings at NSPI year-over-year due to higher income tax expense, decreased sales volumes due to warmer weather, and lower commercial sales related to the impact of COVID-19. The decrease was partially offset by decreased operating, maintenance and general ("OM&G") expense and increased mix of residential sales related to COVID-19	1	(12)
Decreased earnings due to the sale of Emera Maine in Q1 2020 and the sale of Emera Energy's NEGG and Bayside generation facilities in Q1 2019	(8)	(62)
Tax Related:		
Recognition of corporate income tax recovery deferred as a regulatory liability in 2018 at BLPC	–	10
Revaluation of Corporate, NSPI and Emera Energy net deferred income tax assets and liabilities due to the Q1 2020 reduction in the Nova Scotia provincial corporate income tax rate	–	(14)
Q3 2019 recognition of tax benefits related to change in treatment of net operating loss ("NOL") carryforwards and tax reform benefits recognized in Q2 2019 in NMGC	–	(19)
Corporate:		
TGH award, net of tax and legal costs. Refer to the "Significant Items Affecting Earnings" section and note 27 of the consolidated financial statements	36	36
Decreased interest expense in the Other segment primarily due to lower interest rates and repayment of corporate long-term debt	10	30
2019 recognition of corporate loss for the share of the unrecoverable loss on GBPC's facilities related to Hurricane Dorian	6	15
Timing of Q4 preferred share dividend declaration	(11)	–
Other Variances:	(15)	(10)
Adjusted net income – 2020	**$ 188**	**$ 665**

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

For the millions of Canadian dollars			Year ended December 31
	2020	2019	2018
Operating cash flow before changes in working capital	**$ 1,420**	$ 1,598	$ 1,806
Change in working capital	**217**	(73)	(116)
Operating cash flow	**$ 1,637**	$ 1,525	$ 1,690
Investing cash flow	**$ (1,224)**	$ (1,617)	$ (2,190)
Financing cash flow	**$ (372)**	$ 14	$ 344

As at millions of Canadian dollars			December 31
	2020	2019	2018
Total assets	**$ 31,234**	$ 31,842	$ 32,314
Total long-term debt (including current portion)	**$ 13,721**	$ 14,180	$ 15,411

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

CONSOLIDATED INCOME STATEMENT HIGHLIGHTS

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31	Variance		Year ended December 31	Variance	Year ended December 31
	2020	2019		**2020**	2019		2018
Operating revenues	**$ 1,537**	$ 1,616	$ (79)	**$ 5,506**	$ 6,111	$ (605)	$ 6,524
Operating expenses	**1,148**	1,237	89	**4,359**	4,768	409	5,126
Income from operations	**389**	379	10	**1,147**	1,343	(196)	1,398
Income from equity investments	**36**	36	–	**149**	154	(5)	154
Other income (expenses), net	**75**	1	74	**708**	12	696	(23)
Interest expense, net	**159**	181	22	**679**	738	59	713
Income tax expense	**57**	43	(14)	**341**	61	(280)	69
Net income	**284**	192	92	**984**	710	274	747
Net income attributable to common shareholders	**273**	193	80	**938**	663	275	710
Gain on sale, net of tax and transaction costs	**–**	–	–	**309**	–	309	–
Impairment charges, net of tax	**–**	(34)	34	**(26)**	(34)	8	–
After-tax MTM gains (losses)	**85**	82	3	**(10)**	76	(86)	39
Adjusted net income attributable to common shareholders	**$ 188**	$ 145	$ 43	**$ 665**	$ 621	$ 44	$ 671
Earnings per common share – basic	**$ 1.09**	$ 0.79	$ 0.30	**$ 3.78**	$ 2.76	$ 1.02	$ 3.05
Earnings per common share – diluted	**$ 1.08**	$ 0.80	$ 0.28	**$ 3.78**	$ 2.76	$ 1.02	$ 3.04
Adjusted earnings per common share – basic	**$ 0.75**	$ 0.60	$ 0.15	**$ 2.68**	$ 2.59	$ 0.09	$ 2.88
Dividends per common share declared	**$ 0.6375**	$ –	$ 0.6375	**$ 2.4750**	$ 2.3750	$ 0.1000	$ 2.2825
Adjusted EBITDA	**$ 599**	$ 557	$ 42	**$ 2,343**	$ 2,339	$ 4	$ 2,387

Operating Revenues

For the fourth quarter of 2020, operating revenues decreased $79 million compared to the fourth quarter in 2019. Absent decreased MTM gains of $10 million, operating revenues decreased $69 million due to:

- $64 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $18 million decrease in the Other Electric Utilities segment due to lower fuel revenues as a result of lower fuel prices at BLPC; and
- $13 million decrease in the Florida Electric Utility segment due lower clause revenues as a result of a decrease in fuel costs, partially offset by the in-service of solar generation projects, colder weather than the prior quarter, a greater mix of residential sales related to COVID-19, and customer growth.

These impacts were partially offset by:

- $13 million increase at NSPI in the Canadian Electric Utilities segment due to higher Maritime Link assessment revenue compared to 2019 and increased residential sales volumes primarily due to the impact of the COVID-19 pandemic, increased industrial sales volumes, and increased fuel-related pricing. This was partially offset by decreased sales volumes due to warmer weather than the prior year and lower commercial sales volumes related to the impact of the COVID-19 pandemic.

For the year ended December 31, 2020, operating revenues decreased $605 million compared to 2019. Absent increased MTM losses of $148 million, operating revenues decreased by $457 million due to:

- $211 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020;
- $127 million decrease in the Florida Electric Utility segment due to lower clause-related revenue as a result of a decrease in fuel costs, partially offset by the in-service of solar generation projects, a greater mix of residential sales related to the impact of COVID-19, warmer weather than the prior year, and customer growth;
- $109 million decrease in the Other segment due to the sale of NEGG and Bayside in Q1 2019;
- $61 million decrease in the Gas Utilities and Infrastructure segment as a result of lower clause-related revenue at PGS, lower off-system sales at PGS, warmer weather than the prior year at NMGC, NMGC's recognition of tax reform benefits in 2019 and lower commercial sales at PGS related to the COVID-19 pandemic. This was partially offset by customer growth at PGS; and
- $59 million decrease in the Other Electric Utilities segment due lower fuel revenue as a result of lower fuel prices at BLPC, the impact of the COVID-19 pandemic at GBPC and BLPC, and the impact of Hurricane Dorian at GBPC.

These impacts were partially offset by:

- $64 million increase at NSPI in the Canadian Electric Utilities segment, due to higher Maritime Link assessment revenue compared to 2019, increased fuel related pricing, and higher mix of residential sales volumes, partially offset by warmer weather than prior year and decreased commercial sales volumes related to the impact of the COVID-19 pandemic.

Operating Expenses

For the fourth quarter of 2020, operating expenses decreased $89 million compared to the fourth quarter of 2019. Absent the $34 million impairment charge in Q4 2019 and decreased MTM losses of $1 million, operating expenses decreased by $54 million due to:

- $49 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020; and
- $25 million decrease in the Florida Electric Utility segment due to lower natural gas prices.

These impacts were partially offset by:

- $11 million increase at NSPI in the Canadian Electric Utilities segment mainly due to higher Maritime Link assessment costs in 2020, partially offset by decreased OM&G expenses and changes in regulatory deferrals; and
- $10 million increase in the Gas Utilities and Infrastructure segment due to higher commodity costs at PGS and NMGC.

For the year ended December 31, 2020, operating expenses decreased $409 million compared to 2019. Absent the decreased impairment charges of $8 million and increased MTM gains of $5 million, operating expenses decreased $396 million due to:

- $196 million decrease in the Florida Electric Utility segment due to lower natural gas prices;
- $148 million decrease in the Other Electric Utilities segment, primarily due to the sale of Emera Maine in Q1 2020;
- $80 million decrease in the Other segment as a result of the sale of NEGG and Bayside facilities in Q1 2019;
- $41 million decrease in the Gas Utilities and Infrastructure segment due to lower commodity costs and lower system supply to customers at PGS and NMGC and lower volume of off-system sales at PGS; and
- $41 million decrease in the Other Electric segment due to lower oil prices at BLPC.

These impacts were partially offset by:

- $61 million increase at NSPI in the Canadian Electric Utilities segment, primarily due to changes in regulatory deferrals, and higher Maritime Links assessments costs in 2020 partially offset by decreased OM&G expenses.

Other Income (Expenses), Net

The increase in other income (expenses), net for the fourth quarter in 2020 was primarily due to the TGH award, the corporate share of unrecoverable loss at GBPC facilities in 2019 related to Hurricane Dorian and increased AFUDC equity earnings in 2020 primarily related to the Big Bend modernization and solar projects at Tampa Electric. For the year ended December 31, 2020, the increase was also due to the pre-tax gain on the sale of Emera Maine.

Interest Expense

Interest expense, net was lower for Q4 2020 and year ended December 31, 2020 compared to 2019 due to lower interest rates and the repayment of corporate debt.

Income Tax Expense

The increase in income tax expense for Q4 2020 compared to the same period in 2019, was primarily due to increased income before provision for income taxes. The increase in income tax expense in 2020, compared to 2019, was primarily due to the gain on the sale of Emera Maine.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the fourth quarter of 2020, net income attributable to common shareholders was favourably impacted by the $3 million increase in after-tax MTM gains and the 2019 impairment charge of $34 million. Absent favourable MTM changes and the impairment charges, adjusted net income attributable to common shareholders increased $43 million. The increase was due to increased contributions from Florida Electric Utility, the TGH award, decreased corporate interest costs and the 2019 corporate share of unrecoverable loss at GBPC related to Hurricane Dorian. These were partially offset by the timing of preferred share dividends and lower earnings contribution from Emera Maine as a result of its sale.

For the year ended December 31, 2020, net income attributable to common shareholders was favourably impacted by the $309 million after-tax gain on the sale of Emera Maine and the impairment charges, and unfavourably impacted by the $86 million increase in after-tax MTM losses, primarily related to Emera Energy. Absent the net gain on sale of Emera Maine, impairment charges, and the unfavourable MTM changes, adjusted net income attributable to common shareholders increased $44 million. The increase was due to higher earnings contribution from Florida Electric Utility, the TGH award, lower corporate interest costs and the 2019 corporate share of unrecoverable loss at GBPC related to Hurricane Dorian. These were partially offset by lower earnings at Emera Maine as a result of its sale in Q1 2020, reduced earnings at NEGG and Bayside facilities as a result of their sale in Q1 2019, lower earnings contribution from NSPI and the Caribbean utilities, revaluation of deferred taxes due to a reduction in the Nova Scotia corporate income tax rate, and the 2019 recognition of tax reform benefits in NMGC.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic and adjusted earnings per common share – basic were higher for the fourth quarter and the year ended December 31, 2020 due to increased earnings as discussed above.

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 CAD for financial reporting. Changes in translation rates, particularly in the value of the USD against the CAD, can positively or adversely affect results.

Earnings from Emera's foreign operations are translated into CAD. In general, Emera's earnings benefit from a weakening CAD and are adversely impacted by a strengthening CAD. The impact of foreign exchange in any period is driven by rate changes, the timing of earnings from foreign operations during the period, the percentage of earnings from foreign operations in the period and the impact of foreign exchange cash flow hedges entered to manage foreign exchange earnings exposure.

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/USD exchange rates for 2020 and 2019 are as follows:

	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Weighted average CAD/USD	**$ 1.30**	$ 1.32	**$ 1.34**	$ 1.33
Period end CAD/USD exchange rate	**$ 1.27**	$ 1.30	**$ 1.27**	$ 1.30

Strengthening of the CAD exchange rates increased earnings by $1 million and decreased adjusted earnings by $1 million in Q4 2020 compared to Q4 2019. The weakening of the CAD exchange rates increased earnings by $19 million and adjusted earnings by $5 million in 2020, compared to 2019.

Consistent with the Company's risk management policies, Emera partially manages currency risks through matching US denominated debt to finance its US operations and uses 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 USD currency.

millions of US dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Florida Electric Utility	**$ 76**	$ 61	**$ 372**	$ 316
Other Electric Utilities	**5**	10	**24**	57
Gas Utilities and Infrastructure (1)	**30**	33	**97**	115
	111	104	**493**	488
Other segment (2)	**5**	(28)	**(102)**	(159)
Total (3)	**$ 116**	$ 76	**$ 391**	$ 329

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from Emera Energy Services, Bear Swamp and interest expense on Emera's USD denominated debt and in 2019, net income from NEGG.
(3) Amounts above do not include the impact of MTM.

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 PANDEMIC

During the year ended December 31, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. Emera's utilities provide essential services and continue to operate to meet customer demand. The Company's priorities continue to be the reliable delivery of essential energy services while maintaining the health and safety of its customers and employees and supporting the communities Emera operates in.

The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis these unfavourable impacts have not had a material financial impact to net earnings primarily due to a change in the mix of sales across customer classes. Lower commercial and industrial sales have been partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather in 2020, particularly in Florida, has further reduced the consolidated impact. The Company has not deferred any costs for future recovery as a result of the pandemic. Capital project delays and supply chain disruptions have also been minimal to date. Management continues to closely monitor developments related to COVID-19.

Governments world-wide have implemented measures intended to address the pandemic. These measures include travel and transportation restrictions, quarantines, physical distancing, closures of commercial and industrial facilities, shutdowns, shelter-in-place orders and other health measures. These measures are adversely impacting global, national and local economies. Global equity markets have experienced significant volatility and governments and central banks are implementing measures designed to stabilize economic conditions. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

In March 2020, Emera activated its company-wide pandemic and business continuity plans, including travel restrictions, directing employees to work remotely whenever possible, restricting access to operating facilities, physical distancing and implementing additional protocols (including the expanded use of personal protective equipment) for work within customers' premises. In jurisdictions where it is safe to do so, some parts of the business have commenced a workplace re-entry strategy. The Company is monitoring recommendations by local and national public health authorities related to COVID-19 and is adjusting operational requirements as needed.

Emera's utilities are working with customers on relief initiatives in response to the effect of the pandemic on customers' ability to pay and their need for continued service. These initiatives have included the temporary suspension of disconnection for non-payment of bills and the development of payment arrangements where necessary. In Q3 2020, most of Emera's utilities resumed disconnection processes for non-payment. As a result of the temporary suspension of disconnections, the Company's utilities experienced an increase in the aging of customer receivables. This trend has begun to reverse as normal disconnection processes resume. There have been no significant customer defaults as a result of bankruptcies with many accounts being secured by deposits. As of December 31, 2020, adjustments to the allowance for credit losses have increased but have not had a material impact on earnings. The full impact of potential credit losses due to customer non-payment is not known at this time. The utilities are continuing to monitor customer accounts and are working with customers on payment arrangements.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. In Q1 2020, the Company updated its principal risks to reflect this uncertainty. For this risk update, refer to the "Risk Management and Financial Instruments" section of this document and note 27 in the consolidated financial statements. The Company has disclosed the impact of this uncertainty on its accounting estimates used in the preparation of the financial statements. For further detail, refer to the "Critical Accounting Estimates" section of this document, and the "Use of Management Estimates" section of note 1 in the consolidated financial statements.

Potential future impacts of COVID-19 on the business may include the following:

- Lower earnings as a result of lower sales volumes due to continued economic slowdowns and the pace and strength of economic recovery;
- Delays of capital projects as a result of construction shutdowns, government restrictions on non-essential capital work, travel restrictions for contractors or supply chain disruptions;
- Deferral of and adjustment to regulatory filings, hearings, decisions and recovery periods; and
- Decreased cash flow from operations due to lower earnings and slower collection of accounts receivable or increased credit losses.

To date, the above have not had a material financial impact on the Company. Future impacts on the business will depend on future developments, including the duration and severity of the pandemic and the pace and strength of the economic recovery.

Refer to the outlook sections below, by segment, for affiliate specific impacts. These segment outlooks are based on the information currently available, however, the total impact of COVID-19 is unknown at this time.

Depending on the duration of the COVID-19 pandemic, the forecasted capital expenditures disclosed below may be delayed due to supply chain disruptions, travel restrictions for contractors or the deferral of non-essential capital work. The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows. For further detail, refer to the "Liquidity and Capital Resources" section of this document.

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 $10 billion USD of assets and approximately 792,500 customers at December 31, 2020. Tampa Electric owns 5,790 MW of generating capacity, of which 78 per cent is natural gas-fired, 12 per cent is coal and 10 per cent is solar. Tampa Electric owns 2,165 kilometres of transmission facilities and 19,250 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.

Due to continued growth in rate base, Tampa Electric anticipates earning near or below the bottom of the allowed ROE range in 2021. Tampa Electric sales volumes are expected to be lower than in 2020, which benefited from weather that was warmer than in recent years. As a result, Tampa Electric anticipates earnings to be slightly lower than in 2020. Tampa Electric expects customer growth rates in 2021 to be consistent with 2020, reflective of current expected economic growth in Florida.

On February 1, 2021, Tampa Electric notified the FPSC of its intent to seek a base rate increase, reflecting incremental revenue requirements of approximately $280 million USD to $295 million USD, effective January 2022. Tampa Electric's proposed rates include recovery for the costs of the first phase of the Big Bend modernization project, 225 MW of utility-scale solar projects, the advanced metering infrastructure ("AMI") investment, and accelerated recovery of the remaining net book value of retiring assets. Tampa Electric also intends to seek approval for Generation Base Rate Adjustments of $130 million USD to recover the costs of the second phase of the Big Bend modernization project and additional utility-scale solar projects in subsequent years. These filing amounts are estimates until Tampa Electric completes and files its detailed case. Tampa Electric expects to file its detailed case on or after April 2, 2021, and a decision by the FPSC is expected by the end of 2021.

On October 3, 2019, the FPSC issued a rule to implement a Storm Protection Plan ("SPP") 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. Tampa Electric submitted its storm protection plan with the FPSC on April 10, 2020. On April 27, 2020, Tampa Electric submitted a settlement agreement with the FPSC which specified a $15 million USD base rate reduction for SPP program costs previously recovered in base rates beginning January 1, 2021. On June 9, 2020, the FPSC approved this settlement agreement. On August 3, 2020, Tampa Electric submitted another settlement agreement to the FPSC for approval, including cost recovery of approximately $39 million USD in proposed storm protection project costs for 2020 and 2021. This cost recovery includes the $15 million USD of costs removed from base rates. This settlement agreement was approved on August 10, 2020 and Tampa Electric's cost recovery began in January 2021. The current approved plan will apply for the years 2020, 2021 and 2022, and Tampa Electric will file a new plan in 2022 to determine cost recovery in 2023, 2024, and 2025.

On February 18, 2020, Tampa Electric announced its intention to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects by the end of 2023. As of December 31, 2020, Tampa Electric has invested approximately $213 million USD in these projects. AFUDC is being earned on these projects during construction. For further detail, refer to the "Developments" section.

Tampa Electric expects to invest approximately $850 million USD through 2023 to modernize the Big Bend Power Station, of which approximately $526 million USD has been invested through December 31, 2020. The modernization project will repower Big Bend Unit 1 with natural gas combined-cycle technology and eliminate coal as this unit's fuel. On June 1, 2020, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant. In addition, Tampa Electric plans to retire Big Bend Unit 2 in 2021. In accordance with Tampa Electric's 2017 settlement agreement, Tampa Electric was not required to request an asset recovery schedule for retired assets until the next depreciation study. On December 30, 2020, Tampa Electric filed a depreciation and dismantlement study and request for capital recovery schedules with the FPSC.

Tampa Electric plans to retire Big Bend Unit 3 in 2023 as it is in the best interest of customers from economic, environmental risk and operational perspectives. Similar to the retirement plan for Unit 1 and Unit 2, Tampa Electric will continue to account for its existing investment in Unit 3 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study.

In 2021, capital investment in the Florida Electric Utility segment is expected to be approximately $1.2 billion USD (2020 – $1.0 billion USD), including AFUDC. Capital projects include solar investments, continuation of the modernization of the Big Bend Power Station, storm hardening investments and AMI.

CANADIAN ELECTRIC UTILITIES

Canadian Electric Utilities includes NSPI and ENL. NSPI is 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. ENL is 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 529,000 customers, NSPI owns 2,433 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") which own 456 MW of capacity. NSPI owns approximately 5,000 kilometres of transmission facilities and 27,000 kilometres of distribution facilities.

Energy from renewable sources will increase upon delivery of the Nova Scotia block ("NS Block") of electricity transmitted through the Maritime Link from the Muskrat Falls hydroelectric project. The NS Block will provide NSPI with approximately 900 GWh of energy annually for 35 years. In addition, for the first 5 years of the NS Block, NSPI is also entitled to receive approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. Nalcor is obligated to offer NSPI a minimum average of 1.2 TWh of energy annually pursuant to this agreement. Delivery of the NS Block is anticipated to commence in 2021.

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 2021 and expects rate base and earnings to be higher than 2020. The impact of the COVID-19 pandemic on Nova's Scotia's economy and warmer than normal weather adversely affected NSPI's sales volumes and earnings in 2020. Assuming normal weather and a modest economic recovery in 2021, NSPI expects sales volumes to be higher than 2020. Depending on the duration and severity of the COVID-19 pandemic and the pace and strength of economic recovery, NSPI may continue to experience adverse impacts on sales volumes in 2021.

NSPI is currently operating under a 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 below in the "ENL, NSPML" section).

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 greenhouse gas ("GHG") emissions regulations. The current Equivalency Agreement, which must be renewed in five year increments, provides equivalency for the 2020-2024 period and outlines the framework for equivalency for the 2025 to 2040 period. At December 31, 2020, NSPI was in compliance with provincial requirements.

On November 19, 2020, the Government of Canada introduced Bill C-12, "Canadian Net-Zero Emissions Accountability Act", which requires national targets be set for the reduction of GHG emissions in Canada, with the objective of attaining net-zero emissions by 2050. NSPI continues to work with the federal government on measures to address their carbon reduction goals.

On December 11, 2020, the federal government announced plans to increase the carbon tax in Canada starting in 2023, increasing $15 per tonne annually and reaching $170 per tonne by 2030, under the Greenhouse Gas Pollution Pricing Act ("GGPPA"). The GGPPA is a federal back stop for a price on carbon. As Nova Scotia prices carbon through the Nova Scotia Cap-and-Trade Program Regulations, it is NSPI's expectation that Nova Scotia's regulations will be considered equivalent to the proposed carbon tax under the GGPPA. NSPI will continue to work with the provincial government to understand their approach to changes to the Cap-and-Trade Program after 2022 to address the federal government's plans.

NSPI will receive its 2021 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations in Q1 2021. These allowances will be used in 2021 or allocated within the initial four-year compliance period that ends in 2022. 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.

Over the past several years, the requirement to reduce Nova Scotia's reliance upon higher carbon and GHG emitting sources of energy has resulted in NSPI making significant investments in renewable energy sources, including energy from the Maritime Link, and purchasing renewable energy from IPP's.

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. Nalcor resumed work in May 2020 and continues to work toward construction completion and project commissioning in 2021. Refer to the "ENL, Impact of COVID-19 on Muskrat Falls and LIL" section below for further details. Due to the delay of the NS Block, NSPI did not achieve the provincially legislated target of 40 per cent of electric sales generated from renewable sources in 2020. This would have given rise to non-compliance except that on May 15, 2020, the provincial government provided NSPI with an alternative compliance plan, as permitted by the legislation, which requires NSPI to supply customers with at least 40 per cent of energy generated from renewable sources over the 2020 to 2022 period. NSPI expects to achieve this alternative compliance standard.

In 2021, NSPI expects to invest approximately $370 million (2020 – $316 million), including AFUDC, primarily in capital projects to support system reliability and hydroelectric infrastructure renewal investments.

ENL

NSPML

Through its subsidiary, NSPML, ENL has invested $1.9 billion of equity, debt and working capital, including $209 million of AFUDC, in the development of the Maritime Link Project. This investment consists of $546 million in equity, comprised of $443 million in equity contribution and $103 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 assets 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.

Equity earnings 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 December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment for recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million on similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block. Recovery of this interim assessment began on January 1, 2021. NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls which is expected to take place in 2021.

In 2021, NSPML expects to invest approximately $15 million (2020 – $7 million) in capital.

LIL

ENL is a limited partner with Nalcor Energy in LIL, with total project costs 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 value of the equity investment and the approved ROE. Emera's current equity investment is $628 million, comprised of $410 million in equity contribution and $218 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.

Cash earnings and return of equity will begin after commissioning of the LIL by Nalcor, and until that point Emera will continue to record AFUDC earnings.

Equity earnings from NSPML and LIL are expected to be higher in 2021, compared to 2020. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

Impact of COVID-19 on Muskrat Falls and LIL

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor resumed work in May 2020. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward project commissioning in 2021.

OTHER ELECTRIC UTILITIES

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, a 51.9 per cent interest in Domlec on the island of Dominica and a 19.5 per cent interest in Lucelec on the island of St. Lucia which is accounted for on the equity basis.

On March 24, 2020, Emera completed the sale of Emera Maine which is included in the Other Electric Utilities segment for Q1 2020 and all of 2019. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

BLPC

With approximately $466 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 four per cent is solar. The utility has an additional 12 MW of capacity from rental units through March 31, 2021. BLPC owns approximately 184 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 $320 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 138 kilometres of transmission facilities and 860 kilometres of distribution facilities. The utility has an additional 18 MW of capacity from rental units which are expected to be returned in the first half of 2021, when the generation units damaged by Hurricane Dorian are returned to service. In January 2021, the GBPA approved GBPC's regulated return on rate base of 8.37 per cent for 2021 (2020 – 8.34 per cent).

Domlec

Domlec serves approximately 34,000 customers. Domlec owns 26.7 MW of generating capacity, of which 75 per cent is oil-fired and 25 per cent is hydro. Domlec owns approximately 475 kilometres of transmission facilities and 709 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 higher earnings in 2021 from the Caribbean utilities, partially offset by lower earnings contribution due to the sale of Emera Maine in early 2020. Earnings are expected to increase in 2021 as local economies begin to recover from the impacts of COVID-19 and continued recovery from Hurricane Dorian at GBPC.

On November 6, 2020, BLPC notified the Fair Trading Commission ("FTC") that it plans to file a general rate review application with the FTC in Q1 2021.

BLPC operates pursuant to 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.

On September 1, 2019, Hurricane Dorian struck Grand Bahama Island causing significant damage across the island. In January 2020, the GBPA approved the recovery of approximately $15 million USD of restoration costs related to GBPC's self-insured assets. These costs were recorded as a regulatory asset and recovery began January 1, 2021.

In 2021, capital investment in the Other Electric Utilities segment is expected to be approximately $165 million USD (2020 – $111 million USD including $14 million USD invested in Emera Maine projects). Forecasted capital investment is primarily in more efficient and cleaner sources of generation, including renewables and battery storage. BLPC expects to complete installation of a 33MW diesel engine in 2021. This 33 MW plant is expected to increase efficiency and bridge BLPC's transition to increased renewable sources of generation.

GAS UTILITIES AND INFRASTRUCTURE

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

Peoples Gas System

With approximately $1.6 billion USD of assets and approximately 426,000 customers, the PGS system includes approximately 22,200 kilometres of natural gas mains and 12,600 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 2020.

For 2020, the approved ROE range for PGS was 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 was used for the calculation of return on investments for clauses. Beginning in 2021, the approved ROE range is 8.9 per cent to 11.0 per cent, based on an allowed equity capital structure of 54.7 per cent and an ROE of 9.9 per cent will be used for the calculation of return on investments for clauses. See below for further detail.

New Mexico Gas Company, Inc.

With approximately $1.5 billion USD of assets and approximately 540,000 customers, NMGC serves approximately 60 per cent of New Mexico's population in 23 of the state's 33 counties. NMGC's system includes approximately 2,443 kilometres of transmission pipelines and 17,243 kilometres of distribution pipelines. Annual natural gas throughput was approximately 948 million therms in 2020.

For 2020, the approved ROE for NMGC was 9.1 per cent, on an allowed equity capital structure of 52 per cent. New rates became effective August 2019 and were phased in over two years resulting in an annual revenue increase of approximately $3 million USD. In addition, NMGC's weather mechanism became effective October 2019. Beginning in 2021, the approved ROE is 9.375 per cent on an allowed equity capital structure of 52 per cent. See below for further detail.

Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure earnings are anticipated to be higher in 2021 than 2020 primarily due to rate base growth to expand the distribution system and to continue to reliably serve customers.

PGS anticipates earning within its allowed ROE range in 2021 and expects rate base and earnings to be higher than in 2020. PGS expects customer growth in 2021 to be higher than Florida's population growth rates, reflecting expectations of continued strong housing demand in Florida and commercial activity trending back towards normal levels. Assuming normal weather, PGS sales volumes are expected to increase above customer growth, as the COVID-19 pandemic impact on 2021 commercial energy sales is expected to be less than 2020. In January 2021, a base rate increase went into effect in accordance with the FPSC approved rate case settlement and is expected to result in a $34 million USD revenue increase.

PGS was permitted to initiate a general base rate proceeding during 2020, provided the new rates do not become effective before January 1, 2021. On June 8, 2020, PGS filed a petition for an increase in rates and service charges effective January 2021. On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase in base rates by $58 million USD annually effective January 2021, which is a $34 million USD increase in revenue and $24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. This settlement agreement includes an allowed regulatory ROE range of 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint. It provides PGS the ability to reverse a total of $34 million USD of accumulated depreciation through 2023 and sets new depreciation rates going into effect January 1, 2021 that are consistent with PGS' current overall average depreciation rate. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

NMGC anticipates earning at or near its authorized ROE in 2021 and expects rate base to be higher than 2020. NMGC expects customer growth rates to be consistent with historical trends.

NMGC filed a rate case in December 2019. NMGC reached an unopposed stipulated settlement of the case which was approved by the NMPRC in December 2020. The new rates reflect the recovery of capital investment in pipelines and related infrastructure and results in an increase in revenue of approximately $5 million USD annually effective January 2021. The stipulated settlement agreement includes an allowed regulatory ROE of 9.375 per cent on an allowed equity capital structure of 52 per cent. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2022, unless new federal tax rates are enacted, in which case NMGC can file for new rates to be effective earlier than January 1, 2023.

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 will be treated as a sales-type lease for accounting purposes. The lease of the pipeline lateral to Seminole is anticipated to commence in January 2022. The capital investment is projected to be approximately $100 million USD, with the majority of the project investment completed through 2020. SeaCoast also jointly developed the 26.5 mile, 16-inch Callahan Pipeline with Peninsula Pipeline Co., an affiliate of Florida Public Utilities. The SeaCoast pipeline went into service in Q4 2020 providing long-term firm gas transportation service to PGS in the northeast Florida area with 2021 being the first full year of operation. SeaCoast's portion of the capital investment in the Callahan Pipeline was approximately $30 million USD.

In 2021, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $425 million USD (2020 – $553 million USD), including AFUDC. PGS will make investments to expand its system and support customer growth. NMGC completed the Santa Fe Mainline Looping project in January 2021 and will continue to invest in system improvements.

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; 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.

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 usually providing the greatest opportunity for earnings. EES 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 COVID-19 related economic slowdown did not have a material impact on EES earnings in 2020. The pandemic remains a challenge to the overall economy but is expected to continue to have limited impact on EES operations unless circumstances deteriorate significantly.

Absent the gain on the TGH award in 2020, the adjusted net loss from the Other segment is expected to be lower in 2021, based on EES returning to its normal earnings range.

In 2021, capital investment in the Other segment is expected to be approximately $2 million (2020 – $3 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Consolidated Balance Sheets between December 31, 2019 and December 31, 2020 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Receivables and other assets (current and long-term)	**(226)**	Decreased due to the refund of corporate alternative minimum tax credit ("AMT") carryforwards, lower gas transportation assets at Emera Energy, a refund of prior year income taxes receivable at NSPI, cash collateral positions on derivative instruments at NSPI and lower commodity prices at Emera Energy.
Assets held for sale (current and long-term), net of liabilities	**(691)**	Decreased due to the sale of Emera Maine.
Property, plant and equipment, net of accumulated depreciation and amortization	**1,368**	Increased due to capital additions at Tampa Electric, PGS and NSPI, partially offset by the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Goodwill	**(115)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**(371)**	Decreased due to net repayments on committed credit facilities at TECO Finance, Emera and NSPI, repayment of long-term debt at TECO Finance, and the effect of a stronger CAD on the translation of Emera's foreign affiliates. This was partially offset by a net issuance on committed credit facilities at Tampa Electric and PGS and issuance of long-term debt at NSPI.
Deferred income tax liabilities, net of deferred income tax assets	**321**	Increased due to net utilization of tax loss carryforwards primarily related to the sale of Emera Maine, and tax deductions in excess of accounting depreciation related to property, plant and equipment. The increase was partially offset by the revaluation of net deferred income tax liabilities resulting from enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020 and the effect of a stronger CAD on the translation of Emera's foreign subsidiaries.
Regulatory liabilities (current and long-term)	**(220)**	Decreased due to changes in the fuel adjustment mechanism deferral and derivative instrument deferrals at NSPI, decreased deferred income tax regulatory liabilities primarily due to amortization of excess deferred income taxes related to US Tax Reform at Tampa Electric, PGS and NMGC, and the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Common stock	**489**	Increased due to shares issued under Emera's at-the-market equity plan, the dividend reinvestment plan and stock options exercised.
Accumulated other comprehensive income	**(174)**	Decreased due to the effect of a stronger CAD on the translation of Emera's foreign affiliates.
Retained earnings	**322**	Increased due to the gain on sale of Emera Maine and net income in excess of dividends paid.

DEVELOPMENTS

Increase in Common Dividend

On September 16, 2020, Emera's Board of Directors approved an increase in the annual common share dividend rate to $2.55 from $2.45. The first payment was effective November 16, 2020. Emera also reaffirmed its four to five per cent annual dividend growth rate target through 2022.

Sale of Emera Maine

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of $2.0 billion ($1.4 billion USD), including cash proceeds of $1.4 billion, transferred debt and a working capital adjustment. A gain on sale of $309 million after tax, net of transaction costs, was recognized in the Other segment. Proceeds from the sale were used to support capital investment opportunities within Emera's regulated utilities and to reduce corporate debt.

Tampa Electric Solar Investment

On February 18, 2020, Tampa Electric announced its intention to invest approximately $800 million USD in an additional 600 MW of new utility-scale solar photovoltaic projects by the end of 2023. On completion of these projects, approximately 22 per cent, or 1,250 MW, of Tampa Electric's total generating capacity will be solar.

APPOINTMENTS

Board of Directors

Effective February 12, 2021, Karen Sheriff joined the Emera Board of Directors. Most recently, Ms. Sheriff served as President and Chief Executive Officer of Q9 Networks Inc., a data centre services provider. Before that, she was President and Chief Executive Officer of Bell Aliant, Inc., a telecommunications company.

Executive

On February 9, 2021, Emera announced that Archie Collins was appointed President and Chief Executive Officer of Tampa Electric Company effective May 3, 2021. Until that time, Mr. Collins will serve as President and Chief Operating Officer and was most recently the Chief Operating Officer of Tampa Electric Company. Mr. Collins will succeed Nancy Tower who is retiring in June 2021.

Effective October 14, 2020, Peter Gregg was appointed President and CEO of NSPI. Most recently, Mr. Gregg was the President and CEO of the Independent Electricity System Operator in Ontario. Mr. Gregg succeeded Richard Janega, who was appointed interim President and CEO of NSPI effective June 1, 2020. Mr. Janega is Emera's Chief Operating Officer, Electric Utilities, Canada, US Northeast and Caribbean.

OUTSTANDING COMMON STOCK DATA

Common stock **Issued and outstanding:**	millions of shares	millions of Canadian dollars
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
Issuance of common stock (2)	4.54	251
Issued for cash under Purchase Plans at market rate	3.99	219
Discount on shares purchased under Dividend Reinvestment Plan	–	(4)
Options exercised under senior management stock option plan	0.42	20
Employee Share Purchase Plan	–	3
Balance, December 31, 2020	**251.43**	**$ 6,705**

(1) As at December 31, 2019, 1,768,120 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.56 per share for gross proceeds of $100 million ($99 million net of issuance costs).

(2) In Q4 2020, 1,835,422 common shares were issued under Emera's ATM program at an average price of $55.19 per share for gross proceeds of $102 million ($100 million net of issuance costs). For the year ended December 31, 2020, 4,544,025 common shares were issued under Emera's ATM program at an average price of $56.04 per share for gross proceeds of $255 million ($251 million net of issuance costs). As at December 31, 2020, an aggregate gross sales limit of $245 million remains available for issuance under the ATM program.

As at February 9, 2021, the amount of issued and outstanding common shares was 251.6 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, 2020 was 251.3 million (2019 – 242.9 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2020 was 247.8 million (2019 – 239.9 million).

At-The-Market Equity Program

On November 17, 2020, Emera filed an amendment to its July 11, 2019 prospectus supplement which established its ATM program. This amendment reflected changes in securities regulations related to ATM programs which were effective August 31, 2020. The amendment includes removal of the daily trading limit which previously provided that the number of shares sold could not exceed 25 per cent of the daily trading volume of the shares.

Cumulative Preferred Stock

For details regarding cumulative preferred stock, refer to note 28 in Emera's 2020 annual audited financial statements, with updates as noted below:

On July 9, 2020, Emera announced it would not redeem the Cumulative Rate Reset Preferred Shares, Series A ("Series A Shares") or the Cumulative Floating Rate First Preferred Shares, Series B ("Series B Shares"). On August 17, 2020, Emera announced 128,610 of its 3,864,636 issued and outstanding Series A Shares were tendered for conversion into Series B Shares and 1,130,788 of its 2,135,364 issued and outstanding Series B Shares were tendered for conversion into Series A Shares, all on a one-for-one basis. As a result of the conversion, Emera has 4,866,814 Series A Shares and 1,133,186 Series B Shares issued and outstanding.

On July 16, 2020, Emera announced a dividend rate of 2.182 per cent per annum on the Series A Shares during the five-year period which commenced on August 15, 2020 and ends on (and inclusive of) August 14, 2025 ($0.1364 per Series A Share per quarter). Emera also announced a dividend rate of 2.021 per cent on the Series B Shares for the three-month period which commenced on August 15, 2020 and ended on (and inclusive of) November 14, 2020 ($0.1274 per Series B Share for the quarter).

FINANCIAL HIGHLIGHTS

FLORIDA ELECTRIC UTILITY

All amounts are reported in USD, unless otherwise stated.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 468**	$ 473	**$ 1,849**	$ 1,965
Regulated fuel for generation and purchased power	**$ 127**	$ 143	**$ 428**	$ 582
Contribution to consolidated net income	**$ 76**	$ 61	**$ 372**	$ 316
Contribution to consolidated net income – CAD	**$ 101**	$ 80	**$ 501**	$ 419
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.40**	$ 0.33	**$ 2.02**	$ 1.75
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.31**	$ 1.32	**$ 1.34**	$ 1.33
EBITDA	**$ 201**	$ 187	**$ 891**	$ 828
EBITDA – CAD	**$ 263**	$ 245	**$ 1,196**	$ 1,098

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ 61**	**$ 316**
Decreased operating revenues – see Operating Revenues – Regulated Electric below	(5)	(116)
Decreased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	16	154
Increased depreciation due to increased property, plant and equipment	(4)	(19)
Decreased amortization expenses resulting from a credit to accumulated amortization reserve surplus for intangible software assets as approved by the regulator	4	16
Increased AFUDC earnings due to the Big Bend Power Station modernization and solar projects	5	15
Other	(1)	6
Contribution to consolidated net income – 2020	**$ 76**	**$ 372**

Florida Electric Utility's CAD contribution to consolidated net income increased $21 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Florida Electric Utility's CAD contribution to consolidated net income increased $82 million, compared to 2019. The increase in both periods was due to increased base revenues, as described below, and higher AFUDC earnings as a result of the Big Bend Power Station modernization and solar projects. Operating revenues decreased due to lower clause revenues; however, base revenues increased as a result of the in-service of solar generation projects, a greater mix of residential sales related to COVID-19, warmer weather than in the prior year and customer growth.

The impact of the change in the foreign exchange rate decreased CAD earnings for the quarter by $1 million and increased CAD earnings at year ended December 31, 2020 by $6 million.

Operating Revenues – Regulated Electric

Electric revenues decreased $5 million to $468 million in Q4 2020, compared to $473 million in Q4 2019. For the year ended December 31, 2020, electric revenues decreased $116 million to $1,849 million, from $1,965 million in 2019. The decreases in both periods were due to lower clause revenues as a result of a decrease in fuel cost, partially offset by the in-service of solar generation projects, predominately warmer weather than in prior year, a greater mix of residential sales related to COVID-19 and customer growth.

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

Q4 Electric Revenues

millions of US dollars

	2020	2019
Residential	**$ 256**	$ 254
Commercial	**132**	141
Industrial	**34**	39
Other [1]	**46**	39
Total	**$ 468**	$ 473

(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

	2020	2019
Residential	**$ 1,018**	$ 1,046
Commercial	**506**	562
Industrial	**133**	156
Other [1]	**192**	201
Total	**$ 1,849**	$ 1,965

(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")

	2020	2019
Residential	**2,465**	2,303
Commercial	**1,526**	1,536
Industrial	**460**	501
Other	**515**	579
Total	**4,966**	4,919

Annual Electric Sales Volumes

GWh

	2020	2019
Residential	**10,122**	9,584
Commercial	**6,058**	6,240
Industrial	**1,891**	2,021
Other	**1,958**	2,094
Total	**20,029**	19,939

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 5,790 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 $16 million to $127 million in Q4 2020, compared to $143 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power decreased $154 million to $428 million, compared to $582 million in 2019. The decrease in both periods was due to lower natural gas prices and increased solar generation.

Q4 Production Volumes

GWh

	2020	2019
Natural gas	**3,616**	4,075
Coal	**344**	323
Solar	**232**	169
Purchased power	**747**	210
Total	**4,939**	4,777

Annual Production Volumes

GWh

	2020	2019
Natural gas	**16,523**	17,514
Coal	**904**	1,214
Solar	**1,120**	756
Purchased power	**2,513**	1,290
Total	**21,060**	20,774

Q4 Average Fuel Costs

US dollars

	2020	2019
Dollars per Megawatt hour ("MWh")	**$ 26**	$ 30

Annual Average Fuel Costs

US dollars

	2020	2019
Dollars per MWh	**$ 20**	$ 28

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 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 decreased in Q4 2020 and for the year ended December 31, 2020, compared to 2019, due to lower natural gas prices and increased use of solar generation which has no fuel cost.

Regulatory Recovery Mechanisms

Tampa Electric is regulated by 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.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2020, Tampa Electric has invested $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 600 MW or $104 million USD annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates that were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A $5 million USD true-up was returned to customers in 2020. The true-ups for SoBRA tranches 3 and 4 will be filed in 2021 and 2022, respectively.

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.

Storm Protection Plan Cost Recovery Clause

Tampa Electric has a Storm Protection Plan cost recovery clause allowing recovery of prudent transmission and distribution storm hardening costs for incremental activities not already included in base rates as outlined in the programs in its approved Storm Protection Plan. Differences between the prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred 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 to replenish the reserve.

CANADIAN ELECTRIC UTILITIES

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 377**	$ 364	**$ 1,494**	$ 1,430
Regulated fuel for generation and purchased power (1)	**$ 219**	$ 183	**$ 721**	$ 663
Income from equity investments	**$ 21**	$ 23	**$ 96**	$ 91
Contribution to consolidated net income	**$ 57**	$ 58	**$ 221**	$ 229
Contribution to consolidated earnings per common share – basic	**$ 0.23**	$ 0.24	**$ 0.89**	$ 0.95
EBITDA	**$ 157**	$ 151	**$ 614**	$ 592

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

Canadian Electric Utilities' contribution to consolidated net income is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
NSPI	**$ 36**	$ 35	**$ 125**	$ 138
Equity investment in LIL	**12**	12	**49**	45
Equity investment in NSPML	**9**	11	**47**	46
Contribution to consolidated net income	**$ 57**	$ 58	**$ 221**	$ 229

Net Income

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ 58**	**$ 229**
Increased operating revenues – see Operating Revenues – Regulated Electric below	13	64
Increased fuel for generation and purchased power – see Regulated Fuel for Generation and Purchased Power below	(36)	(58)
Decreased FAM expense in the quarter primarily due to the refund of prior years' over-recovery of fuel costs, partially offset by increased recoveries of current period fuel costs. Year-over-year increase in FAM expense due to over recoveries of current period fuel costs and the prior year recovery of the reduced Maritime Link assessment returned to customers in subsequent years. This was partially offset by the refund of customers of prior years' over-recovery of fuel costs.	12	(28)
Decreased OM&G expense quarter-over-quarter primarily due to lower labour costs, storm restoration costs, power generation and vegetation management costs and decreased demand side management ("DSM") expense. Year-over-year these decreases were partially offset by lower overhead allocated to property, plant and equipment, and COVID-19 pandemic response costs.	14	31
Increased year-over-year due to increased equity earnings from the LIL	(1)	5
Increased income taxes primarily due to a reduction in the non-capital loss carryback as a result of lower tax deductions in excess of accounting depreciation related to property, plant and equipment and the tax benefits of capital investment related to post-tropical storm Dorian in 2019.	(5)	(27)
Other	2	5
Contribution to consolidated net income – 2020	**$ 57**	**$ 221**

Canadian Electric Utilities' contribution to consolidated net income decreased $1 million to $57 million in Q4 2020, compared to $58 million for the same period in 2019. For the year ended December 31, 2020 Canadian Electric Utilities' contribution to consolidated net income decreased $8 million to $221 million compared to $229 million in 2019. The decrease in both periods was due to higher income tax expense, warmer weather than prior year, and lower commercial sales related to COVID-19, partially offset by decreased OM&G expense and increased mix of residential sales related to COVID-19 at NSPI.

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

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $13 million to $377 million in Q4 2020, compared to $364 million in Q4 2019. For the year ended December 31, 2020, operating revenues increased $64 million to $1,494 million, compared to $1,430 million in 2019. The increase in both periods was primarily due to a higher Maritime Link assessment included in revenue compared to 2019, increased fuel-related pricing, and higher residential sales volumes related to COVID-19. This was partially offset by decreased sales volumes due to warmer weather than prior year and decreased commercial sales volumes primarily due to the impact of the COVID-19 pandemic. Quarter-over-quarter was also impacted by increased industrial sales volumes. Year-over-year was also partially offset by decreased other sales volumes.

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

Q4 Electric Revenues

millions of Canadian dollars

	2020	2019
Residential	**$ 199**	$ 194
Commercial	**102**	102
Industrial	**60**	50
Other	**7**	10
Total	**$ 368**	$ 356

Annual Electric Revenues

millions of Canadian dollars

	2020	2019
Residential	**$ 806**	$ 746
Commercial	**405**	400
Industrial	**224**	210
Other	**31**	45
Total	**$ 1,466**	$ 1,401

Q4 Electric Sales Volumes

GWh

	2020	2019
Residential	**1,159**	1,210
Commercial	**712**	763
Industrial	**629**	571
Other	**36**	78
Total	**2,536**	2,622

Annual Electric Sales Volumes

GWh

	2020	2019
Residential	**4,652**	4,664
Commercial	**2,850**	3,068
Industrial	**2,341**	2,388
Other	**185**	350
Total	**10,028**	10,470

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $36 million to $219 million in Q4 2020, compared to $183 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power increased $58 million to $721 million, compared to $663 million in 2019. Changes in both periods were primarily due to higher Maritime Link assessment costs in 2020, changes in generation mix, and increased commodity prices, partially offset by decreased sales volumes.

Q4 Production Volumes

GWh

	2020	2019
Coal	**1,249**	1,398
Natural gas	**351**	322
Oil and petcoke	**174**	149
Purchased power – other	**235**	139
Total non-renewables	**2,009**	2,008
Purchased power – IPP	**353**	371
Wind and hydro	**215**	306
Purchased power – Community Feed-in Tariff program ("COMFIT")	**156**	163
Biomass	**21**	14
Total renewables	**745**	854
Total production volumes	**2,754**	2,862

Annual Production Volumes

GWh

	2020	2019
Coal	**4,342**	4,949
Natural gas	**1,872**	1,369
Oil and petcoke	**967**	981
Purchased power – other	**663**	786
Total non-renewables	**7,844**	8,085
Purchased power – IPP	**1,250**	1,202
Wind and hydro	**1,001**	1,289
Purchased power – COMFIT	**558**	552
Biomass	**106**	73
Total renewables	**2,915**	3,116
Total production volumes	**10,759**	11,201

Q4 Average Fuel Costs

		2020		2019
Dollars per MWh	**$**	**80**	$	64

Annual Average Fuel Costs

		2020		2019
Dollars per MWh	**$**	**67**	$	59

Average fuel cost per MWh increased in Q4 2020 compared to Q4 2019 due to higher Maritime Link assessment costs in 2020 and increased commodity pricing. For the year ended December 31, 2020 compared to the same period in 2019, fuel costs increased due to a change in generation mix resulting from higher natural gas consumption and lower generation from NSPI owned hydro and wind, which have no fuel cost. This was partially offset by lower generation from solid fuel.

NSPI's FAM regulatory liability balance decreased $94 million from $115 million at December 31, 2019 to $21 million at December 31, 2020, primarily due to the refund of prior years' over-recovery of fuel costs and reduced 2019 Maritime Link assessment refunded to customers in 2020. This was partially offset by over-recovery of current-period fuel costs.

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.

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 a reasonable 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.

As part of the three-year fuel stability plan, electricity rates have been set to include the $145 million approved Maritime Link assessment for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million on similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block. Refer to the NSPML section below for further details. Any difference between the amounts included in the fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

OTHER ELECTRIC UTILITIES

All amounts are reported in USD, unless otherwise stated.

On March 24, 2020, Emera completed the sale of Emera Maine. For further detail, refer to the "Significant Items Affecting Earnings" and "Developments" sections.

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated electric	**$ 79**	$ 140	**$ 354**	$ 561
Regulated fuel for generation and purchased power [1]	**35**	58	**145**	216
Adjusted contribution to consolidated net income	**$ 5**	$ 10	**$ 24**	$ 57
Adjusted contribution to consolidated net income – CAD	**$ 8**	$ 14	**$ 33**	$ 76
Impairment charges	**–**	(26)	**–**	(26)
After-tax equity securities MTM gain	**2**	–	**2**	2
Contribution to consolidated net income	**$ 7**	$ (16)	**$ 26**	$ 33
Contribution to consolidated net income – CAD	**$ 10**	$ (19)	**$ 35**	$ 45
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$ 0.03**	$ 0.06	**$ 0.13**	$ 0.32
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.04**	$ (0.08)	**$ 0.14**	$ 0.19
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.28**	$ 1.32	**$ 1.34**	$ 1.33
Adjusted EBITDA	**$ 19**	$ 38	**$ 96**	$ 187
Adjusted EBITDA – CAD	**$ 27**	$ 52	**$ 129**	$ 249

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

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

For the millions of US dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
ECI	**$ 5**	$ 3	**$ 20**	$ 22
Emera Maine	**–**	7	**4**	35
Adjusted contribution to consolidated net income	**$ 5**	$ 10	**$ 24**	$ 57

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ (16)**	**$ 33**
Operating revenues – see Operating Revenues – Regulated Electric below	(12)	(48)
Regulated fuel for generation – see Regulated Fuel for Generation and Purchased Power below	13	41
Recognition of a previously deferred corporate income tax recovery in Q1 2020 related to enactment of a lower corporate income tax rate in December 2018 at BLPC	–	7
GBPC impairment charge in 2019	26	26
Impact on earnings of sale of Emera Maine, net of tax	(7)	(31)
Other	3	(2)
Contribution to consolidated net income – 2020	**$ 7**	**$ 26**

In Q4 2019, the Company recognized a non-cash impairment charge, primarily related to goodwill, 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. No impairment charge related to GBPC was recognized in 2020.

Excluding the change in MTM, the 2019 impairment charges at GBPC and the sale of Emera Maine, Other Electric Utilities CAD's contribution to consolidated net income increased $3 million quarter-over-quarter and decreased $2 million year-over-year. ECI's contribution in Q4 2020 increased due to the continued recovery from Hurricane Dorian. ECI's contribution for the year decreased due to lower commercial sales, partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic, and the impact from Hurricane Dorian at GBPC. The decrease was partially offset by recognition of a previously deferred corporate income tax recovery related to enactment of a lower corporate income tax rate in December 2018 at BLPC.

The foreign exchange rate had minimal impact for the three months and year ended December 31, 2020.

Operating Revenues – Regulated Electric

Operating revenues decreased $61 million to $79 million in Q4 2020, compared to $140 million in Q4 2019. For the year ended December 31, 2020, operating revenues decreased $207 million to $354 million compared to $561 million in 2019. Decreases in both periods were a result of the sale of Emera Maine in Q1 2020, lower fuel revenue at BLPC as a result of lower oil prices, lower commercial sales partially offset by increased sales to residential customers due to the impact of the COVID-19 pandemic, and the impacts of Hurricane Dorian at GBPC. Quarter-over-quarter, GBPC's revenue was higher than Q4 2019 due to the continued recovery from the impacts of Hurricane Dorian in September 2019.

Electric revenues and sales volumes for ECI's utilities are summarized in the following tables by customer class:

Q4 Electric Revenues

millions of USD	2020	2019
Residential	**$ 32**	$ 35
Commercial	**40**	49
Industrial	**5**	6
Other	**2**	3
Total	**$ 79**	$ 93

Annual Electric Revenues

millions of USD	2020	2019
Residential	**$ 116**	$ 125
Commercial	**161**	198
Industrial	**21**	21
Other	**12**	15
Total	**$ 310**	$ 359

Q4 Electric Sales Volumes

GWh	2020	2019
Residential	**124**	115
Commercial	**169**	188
Industrial	**19**	19
Other	**1**	4
Total	**313**	326

Annual Electric Sales Volumes

GWh	2020	2019
Residential	**493**	463
Commercial	**650**	742
Industrial	**80**	78
Other	**17**	15
Total	**1,240**	1,298

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power decreased $23 million to $35 million in Q4 2020, compared to $58 million in Q4 2019. For the year ended December 31, 2020, regulated fuel for generation and purchased power decreased $71 million to $145 million compared to $216 million in 2019. The decreases in both periods were as a result of lower oil prices at BLPC.

Production volumes and average fuel costs for ECI's utilities are summarized in the following tables:

Q4 Production Volumes

GWh	2020	2019
Oil	**314**	332
Hydro	**7**	6
Solar	**4**	4
Purchased Power	**12**	9
Total	**337**	351

Annual Production Volumes

GWh	2020	2019
Oil	**1,247**	1,338
Hydro	**19**	20
Solar	**17**	19
Purchased Power	**52**	34
Total	**1,335**	1,411

Q4 Average Fuel Costs

US dollars		**2020**		2019
Dollars per MWh	**$**	**105**	$	135

Annual Average Fuel Costs

US dollars		**2020**		2019
Dollars per MWh	**$**	**102**	$	125

Average fuel cost per MWh decreased in Q4 2020 and for the year ended December 31, 2020, compared to the same periods in 2019, due to lower oil prices.

Regulatory Recovery Mechanisms

BLPC

BLPC is regulated by the FTC, 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. In 2019 Hurricane Dorian restoration costs for GBPC self-insured assets were $15 million USD. In January 2020, the GBPA approved the deferral of these costs through a regulated asset with recovery through rates over a five-year period. Recovery of the asset began January 1, 2021.

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 7.34 per cent return on rate base and 50 per cent of amounts above 9.34 per cent return on rate base, respectively.

Domlec

Domlec is regulated by the IRC. 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 millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Operating revenues – regulated gas (1)	**$ 234**	$ 228	**$ 780**	$ 832
Operating revenues – non-regulated	**3**	3	**12**	12
Total operating revenue	**$ 237**	$ 231	**$ 792**	$ 844
Regulated cost of natural gas	**$ 80**	$ 76	**$ 221**	$ 264
Income from equity investments	**$ 4**	$ 3	**$ 14**	$ 17
Contribution to consolidated net income	**$ 35**	$ 37	**$ 122**	$ 139
Contribution to consolidated net income – CAD	**$ 45**	$ 51	**$ 162**	$ 183
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.18**	$ 0.21	**$ 0.65**	$ 0.76
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.30**	$ 1.32	**$ 1.33**	$ 1.33
EBITDA	**$ 81**	$ 84	**$ 294**	$ 311
EBITDA – CAD	**$ 104**	$ 114	**$ 392**	$ 413

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2019 – $11 million) for the three months ended December 31, 2020 and $45 million (2019 – $45 million) for the year ended December 31, 2020, 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 millions of US dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
PGS	**$ 13**	$ 12	**$ 52**	$ 54
NMGC	**12**	15	**30**	46
Other	**10**	10	**40**	39
Contribution to adjusted consolidated net income	**$ 35**	$ 37	**$ 122**	$ 139

Net Income

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

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2019	**$ 37**	**$ 139**
Increased (decreased) gas operating revenues – see Operating Revenues – Regulated Gas below	6	(43)
Increased (decreased) cost of natural gas sold – see Regulated Cost of Natural Gas below	(4)	43
Recognition of tax benefits related to change in treatment of NOL carryforwards at NMGC in Q3 2019	–	(5)
Decreased gas operating revenues as a result of recognition of tax reform benefits at NMGC in Q2 2019	–	(9)
Other	(4)	(3)
Contribution to consolidated net income – 2020	**$ 35**	**$ 122**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $6 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Gas Utilities and Infrastructure's CAD contribution to consolidated net income decreased $21 million compared to 2019. The decrease in both periods was the result of lower revenues due to warmer weather at NMGC, impacts of COVID-19 on commercial sales at PGS, and higher OM&G costs at PGS and NMGC. These impacts were partially offset by customer growth at PGS, increased AFUDC earnings at PGS, and higher return on investment in the cast iron and bare steel replacement rider at PGS. For the year ended December 31, 2020, the decrease was also due to the Q3 2019 recognition of tax benefits related to a change in treatment of NOL carryforwards and tax reform benefits recognized in Q2 2019 at NMGC.

The foreign exchange rate had minimal impact on CAD earnings in Q4 2020 and for the year ended December 31, 2020.

Operating Revenues – Regulated Gas

Gas Utilities and Infrastructure's operating revenues increased $6 million to $234 million in Q4 2020, compared to $228 million in Q4 2019 due to higher clause related revenues and customer growth at PGS partially offset by lower off-system sales at PGS and lower commercial sales related to the COVID-19 pandemic at PGS.

For the year ended December 31, 2020, operating revenues decreased $52 million to $780 million, compared to $832 million in 2019 due to lower clause-related revenues, lower off-system sales at PGS, warmer weather at NMGC and lower commercial sales related to the COVID-19 pandemic at PGS. This decrease was partially offset by customer growth at PGS. For the year ended December 31, 2020, the decrease was also due to NMGC's recognition of tax reform benefits in Q2 2019.

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

Q4 Gas Revenues

millions of US dollars

	2020	2019
Residential	**$ 122**	$ 109
Commercial	**63**	63
Industrial (1)	**11**	9
Other (2)	**27**	36
Total (3)	**$ 223**	$ 217

(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 (2019 – $11 million).

Annual Gas Revenues

millions of US dollars

	2020	2019
Residential	**$ 372**	$ 379
Commercial	**207**	225
Industrial (1)	**41**	37
Other (2)	**115**	146
Total (3)	**$ 735**	$ 787

(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 (2019 – $45 million).

Q4 Gas Volumes

Therms (millions)

	2020	2019
Residential	**132**	138
Commercial	**220**	225
Industrial	**388**	376
Other	**59**	88
Total	**799**	827

Annual Gas Volumes

Therms (millions)

	2020	2019
Residential	**405**	413
Commercial	**767**	830
Industrial	**1,586**	1,482
Other	**298**	317
Total	**3,056**	3,042

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, if requested, to provide transportation-only services for all customer classes. Because the commodity portion of bundled sales is included in operating revenues, at the cost of the gas on a pass-through basis, there is no net earnings effect when a customer shifts to transportation-only sales.

Regulated cost of natural gas increased $4 million to $80 million in Q4 2020, compared to $76 million in Q4 2019 due to higher commodity costs at PGS and NMGC.

For the year ended December 31, 2020, regulated cost of natural gas decreased $43 million to $221 million in Q4 2020, compared to $264 million in 2019. The decrease was due to lower commodity costs at PGS and NMGC in the first three quarters of the year, lower system supply to customers and lower volume of off-system sales at PGS.

Gas sales by type are summarized in the following table:

Q4 Gas Volumes by Type

Therms (millions)	2020	2019
System supply	**197**	235
Transportation	**602**	592
Total	**799**	827

Annual Gas Volumes by Type

Therms (millions)	2020	2019
System supply	**690**	754
Transportation	**2,366**	2,288
Total	**3,056**	3,042

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. In February 2017, the FPSC approved expansion of the Cast Iron/Bare Steel clause to allow recovery of accelerated replacement of certain obsolete plastic pipe. PGS estimates that all cast iron and bare steel pipe will be removed from its system by 2022, with 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 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

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 October through April heating seasons. The Weather Normalization Mechanism will allow customer rates and company revenue to be 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.

IMP Regulatory Asset

A portion of NMGC's annual spend on infrastructure is for integrity management programs ("IMP"), or the replacement and update of legacy systems. These programs are driven both by NMGC integrity management plans and federal and state mandates. In December 2020, NMGC received approval through its rate case to defer costs through an IMP regulatory asset for certain of its IMP capital investments occurring between January 1, 2022 and December 31, 2023 and will seek recovery for the regulatory asset in its next rate case filing.

OTHER

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Marketing and trading margin (1) (2)	**$ 22**	$ 28	**$ 38**	$ 31
Electricity and capacity sales (3)	**4**	2	**16**	118
Other non-regulated operating revenue	**8**	1	**21**	31
Total operating revenues – non-regulated	**$ 34**	$ 31	**$ 75**	$ 180
Intercompany revenue (4)	**3**	3	**13**	20
Non-regulated fuel for generation and purchased power (5)	**3**	2	**15**	68
Income from equity investments	**7**	7	**24**	32
Interest expense, net	**71**	81	**301**	337
Adjusted contribution to consolidated net income (loss)	**$ (23)**	$ (58)	**$ (252)**	$ (286)
Gain on sale, net of tax and transaction costs	**–**	–	**309**	–
Impairment charges, net of tax	**–**	–	**(26)**	–
After-tax derivative MTM gain (loss)	**$ 83**	$ 81	**$ (12)**	$ 73
Contribution to consolidated net income (loss)	**$ 60**	$ 23	**$ 19**	$ (213)
Adjusted contribution to consolidated earnings per common share – basic	**$ (0.09)**	$ (0.24)	**$ (1.02)**	$ (1.19)
Contribution to consolidated earnings per common share – basic	**$ 0.24**	$ 0.09	**$ 0.08**	$ (0.89)
Adjusted EBITDA	**$ 50**	$ 2	**$ 25**	$ 9

(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 MTM gain of $109 million in Q4 2020 (2019 – $119 million gain) and a loss of $46 million for the year ended December 31,2020 (2019 – $100 million gain).
(3) Electricity and capacity sales exclude a pre-tax MTM of nil in Q4 2020 (2019 – nil) and nil for the year ended December 31, 2020 (2019 – $2 million gain).
(4) Intercompany revenue consists of interest from Brunswick Pipeline and M&NP.
(5) Non-regulated fuel for generation and purchased power excludes a pre-tax MTM of nil in Q4 2020 (2019 – $1 million loss) and a $3 million gain for the year ended December 31, 2020 (2019 – $2 million loss).

Other's adjusted contribution to consolidated net income is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Emera Energy	**$ 15**	$ 18	**$ 17**	$ 37
Corporate	**(37)**	(75)	**(267)**	(322)
Other	**(1)**	(1)	**(2)**	(1)
Adjusted contribution to consolidated net income (loss)	**$ (23)**	$ (58)	**$ (252)**	$ (286)

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 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 pricing 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.

In 2020 Emera Corporate entered into foreign exchange forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the foreign exchange rate result in MTM gains or losses recorded in income.

Net Income

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

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income (loss) – 2019	**$ 23**	**$ (213)**
Increased (decreased) marketing and trading margin – see Emera Energy below	(6)	7
Decreased other income due to 2019 gain on sale of property in Florida, net of tax	–	(10)
Decreased interest expense primarily due to lower interest rates and repayment of corporate long-term debt	10	30
Revaluation of net deferred income tax assets resulting from the enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020, including $2 million recovery related to MTM	–	(11)
Timing of preferred stock dividends issued	(11)	–
TGH award, net of tax and legal costs	36	36
Impact of sale of NEGG and Bayside Power, net of tax	1	(21)
Impairment charges recognized on certain other assets	–	(26)
Gain on sale of Emera Maine, net of tax and transaction costs	–	309
Changes in MTM gains and losses in both periods are due to changes in existing hedging positions and changes in amortization on gas transportation assets at Emera Energy, partially offset by foreign exchange gains on cash flow hedges	2	(87)
Decreased income from Bear Swamp equity investment due to reduced energy deliveries resulting from a third-party transmission line outage, lower New England capacity prices and less favourable energy conditions	–	(8)
2019 Corporate share of the unrecoverable loss at GBPC facilities	6	15
Other	(1)	(2)
Contribution to consolidated net income (loss) – 2020	**$ 60**	**$ 19**

Excluding the change in MTM, gain on sale of Emera Maine and impairment charges recognized on certain other assets, Other's contribution to consolidated net income increased by $35 million in Q4 2020, compared to Q4 2019. For the year ended December 31, 2020, Other's contribution to consolidated net income increased $34 million, compared to the same period in 2019. The increase in both periods was primarily due to the TGH award, lower corporate interest and the 2019 recognition of the Corporate share of the unrecoverable loss on GBPC facilities. The quarter-over-quarter increase was partially offset by timing of preferred stock dividends and decreased marketing and trading margin. Year-over-year increase was also due to higher marketing and trading margin partially offset by the impact of the sale of NEGG and Bayside, revaluation of net deferred income tax assets resulting from the Q1 2020 enactment of a lower Nova Scotia provincial corporate income tax rate, and the 2019 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 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

Marketing and trading margin decreased $6 million in Q4 2020, compared to Q4 2019 primarily due to lower hedged margin net of fixed commitments for gas transportation and storage.

For the year ended December 31, 2020, marketing and trading margin increased $7 million compared to the same period in 2019. This increase was primarily due to increased hedged margin net of fixed commitments for gas transportation storage assets in the summer months, partially offset by less favourable winter market conditions, specifically warmer than normal Q1 winter weather and lower natural gas prices in 2020 compared to 2019.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates internally sourced cash from its various regulated and non-regulated energy investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include general economic downturns in markets served by Emera, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets and changes in environmental legislation. Emera's subsidiaries 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.

During the year ended December 31, 2020, the effects of the ongoing COVID-19 pandemic including the resulting government measures to address this pandemic have resulted in economic slowdowns in all markets served by Emera. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis, these unfavourable impacts have not had a material impact to consolidated net earnings. Refer to the "Business Overview and Outlook – COVID-19 Pandemic" section of this document for further discussion. The ongoing economic impact of the pandemic may affect customers' ability to pay. As a result of the temporary suspension of disconnections, the Company's utilities experienced an increase in the aging of customer receivables. This trend has begun to reverse as normal disconnection processes resume. There have been no significant customer defaults as a result of bankruptcies with many customer accounts secured by deposits. As of December 31, 2020, adjustments to the allowance for credit losses have increased but have not had a material impact on earnings. The full impact of potential credit losses due to customer non-payment is not known at this time. The utilities are continuing to monitor customer accounts and are working with customers on payment arrangements.

The extent of the future impact of COVID-19 on the Company's operating cash flow cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. The Company currently expects to continue to have adequate liquidity given its cash position, existing bank facilities, and access to capital, but will continue to monitor the impact of COVID-19 on future cash flows.

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 $7.4 billion capital investment plan over the 2021-to-2023 period and the potential for additional capital opportunities of $1.2 billion over the same 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. The extent of the future impact of COVID-19 on the profile of the Company's capital plan cannot be predicted at this time due to reasons discussed earlier. The Company has flexibility with respect to its capital investment plan and will continue to monitor current events and related impacts of COVID-19.

Emera plans to use cash from operations and debt raised at the utilities 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. The Company's future access to capital may be impacted by possible COVID-19 related market disruptions. Refer to the "Risk Management and Financial Instruments" section of this document.

Emera has credit facilities with varying maturities that cumulatively provide $3.7 billion of credit, with approximately $1.7 billion undrawn and available at December 31, 2020. The Company was holding a cash balance of $254 million at December 31, 2020. Refer to the "Debt Management" section below for further details. Refer to notes 23 and 25 in the consolidated financial statements for additional information regarding the credit facilities.

CONSOLIDATED CASH FLOW HIGHLIGHTS

Significant changes in the statements of cash flows between the years ended December 31, 2020 and 2019 include:

millions of Canadian dollars	**2020**	2019	$ Change
Cash, cash equivalents and restricted cash, beginning of period	**$ 274**	$ 372	$ (98)
Provided by (used in):			
Operating cash flow before changes in working capital	**1,420**	1,598	(178)
Change in working capital	**217**	(73)	290
Operating activities	**1,637**	1,525	112
Investing activities	**(1,224)**	(1,617)	393
Financing activities	**(372)**	14	(386)
Effect of exchange rate changes on cash and cash equivalents	**(61)**	(20)	(41)
Cash, cash equivalents, restricted cash and cash included in assets held for sale, end of period	**$ 254**	$ 274	$ (20)

Cash Flow from Operating Activities

Net cash provided by operating activities increased $112 million to $1,637 million for the year ended December 31, 2020, compared to $1,525 million in 2019.

Cash from operations before changes in working capital decreased $178 million in 2020. The decrease was primarily due to the impact of the sale of Emera Maine in Q1 2020, lower earnings at NSPI, and higher under-recovery of clause related costs at Tampa Electric.

Changes in working capital increased operating cash flows by $290 million. The increase was due to favourable changes in cash collateral positions on derivative instruments at NSPI, decreased investment in fuel inventory at NSPI, and the receipt in 2020 of a 2019 income tax refund at NSPI. This was partially offset by timing of accounts payable payments at Tampa Electric and NMGC.

Cash Flow Used in Investing Activities

Net cash used in investing activities decreased $393 million to $1,224 million for the year ended December 31, 2020, compared to $1,617 million in 2019. In 2020, Emera received proceeds of $1.4 billion on the sale of Emera Maine, compared to proceeds of $875 million on dispositions in 2019, primarily from the sale of the NEGG and Bayside facilities. This increase in proceeds was partially offset by an increase in capital expenditures in 2020.

Capital expenditures for the year ended December 31, 2020, including AFUDC, were $2,668 million compared to $2,516 million in 2019. Details of the 2020 capital spend by segment are shown below:

- $1,415 million – Florida Electric Utility (2019 – $1,414 million);
- $342 million – Canadian Electric Utilities (2019 – $389 million);
- $149 million – Other Electric Utilities (2019 – $200 million);
- $758 million – Gas Utilities and Infrastructure (2019 – $450 million); and
- $4 million – Other (2019 – $63 million).

Cash Flow from Financing Activities

Net cash used in financing activities increased $386 million to $372 million for the year ended December 31, 2020, compared to cash provided by financing activities of $14 million in 2019. The increase was due to 2019 proceeds from Emera's non-revolving credit facilities, net repayment of debt at TECO Finance, higher net repayments of Emera's committed credit facilities, and lower proceeds from the issuance of long-term debt at NSPI. These were partially offset by a 2019 repayment of corporate long-term debt, proceeds from short-term debt at Tampa Electric and PGS, lower net repayments of NSPI's committed credit facilities and the 2019 retirement of long-term debt at NSPI.

WORKING CAPITAL

As at December 31, 2020, Emera's cash and cash equivalents were $220 million (2019 – $222 million) and Emera's investment in non-cash working capital was $266 million (2019 – $566 million). Of the cash and cash equivalents held at December 31, 2020, $197 million was held by Emera's foreign subsidiaries (2019 – $208 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

CONTRACTUAL OBLIGATIONS

As at December 31, 2020, contractual commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2021	2022	2023	2024	2025	Thereafter	Total
Long-term debt principal	$ 1,382	$ 407	$ 809	$ 820	$ 226	$ 10,182	$ 13,826
Interest payment obligations (1)	585	552	531	516	497	6,364	9,045
Purchased power (2)	231	218	216	218	224	2,242	3,349
Transportation (3)	518	393	339	306	282	2,704	4,542
Pension and post-retirement obligations (4)	30	37	31	32	31	184	345
Capital projects	394	98	76	–	–	–	568
Fuel, gas supply and storage	494	91	6	1	–	–	592
Asset retirement obligations	21	2	2	7	2	391	425
Long-term service agreements (5)	43	41	36	33	34	92	279
Equity investment commitments (6)	–	240	–	–	–	–	240
Leases and other (7)	16	17	16	15	8	118	190
Demand side management	40	45	–	–	–	–	85
Long-term payable	5	5	5	–	–	–	15
	$ 3,759	$ 2,146	$ 2,067	$ 1,948	$ 1,304	$ 22,277	$ 33,501

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2020, including any expected required payment under associated swap agreements.
(2) Annual requirement to purchase electricity production from IPP's or other utilities over varying contract lengths.
(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $149 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(4) 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.
(5) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.
(6) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(7) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing project commissioning in 2021.

NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls, which is anticipated to take place in 2021. On December 16, 2020, the UARB approved NSPML's 2021 interim assessment for recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million with similar terms as previously approved by the UARB and a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. As part of NSPI's 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved the 2021 interim cost assessment of approximately $172 million. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are dependent on regulatory filings with the UARB.

Once Muskrat Falls and LIL have achieved full power, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties relating to the Maritime Link and LIL.

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 could 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, the obligations are included within "Leases and other" in the above table.

FORECASTED GROSS CONSOLIDATED CAPITAL EXPENDITURES

2021 forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Total
Generation	$ 617	$ 150	$ 55	$ –	$ –	$ 822
New renewable generation	176	–	96	–	–	272
Transmission	73	60	2	–	–	135
Distribution	448	100	44	–	–	592
Gas transmission and distribution	–	–	–	509	–	509
Facilities, equipment, vehicles, and other	152	60	16	36	2	266
	$ 1,466	$ 370	$ 213	$ 545	$ 2	$ 2,596

DEBT MANAGEMENT

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.7 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 – Unsecured committed revolving credit facility	June 2024	$ 900	$ 286	$ 614
TEC – in USD – Unsecured committed revolving credit facility (1)	March 2023	800	346	454
NSPI – Unsecured committed revolving credit facility	October 2024	600	300	300
Emera – Unsecured non-revolving facility	December 2021	400	400	–
TECO Finance – in USD – Unsecured committed revolving credit facility	March 2023	400	161	239
TEC – in USD – Unsecured non-revolving facility (1)	February 2021	300	300	–
TEC – in USD – Accounts receivable collateralized borrowing facility (1)	March 2021	150	130	20
NMGC – in USD – Unsecured committed revolving credit facility	March 2023	125	19	106
Other – in USD – Unsecured committed revolving credit facilities	Various	35	20	15

(1) These facilities are available for use by Tampa Electric and PGS. At December 31, 2020, Tampa Electric had utilized $562 million USD and PGS had utilized $214 million USD of the facilities.

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, 2020. Emera's significant covenant is listed below:

	Financial Covenant	**Requirement**	**As at December 31, 2020**
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.56 : 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 on either the London interbank deposit rate ("LIBOR"), prime rate or the federal funds rate, plus a margin. On January 29, 2021, TEC extended the maturity date of the agreement to April 29, 2021 with no other changes in terms.

On December 18, 2020, TEC amended and restated its bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023 and increased the amount of the commitment by the lenders to $800 million USD from $400 million USD. The credit facility bears interest based on either the LIBOR, the Wells Fargo Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $80 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Canadian Electric Utilities

On April 24, 2020, NSPI completed a $300 million 30-year unsecured notes issuance. The notes bear interest at a rate of 3.31 per cent and have a maturity date of April 25, 2050.

Other Electric Utilities

On May 20, 2020, GBPC entered into a $22 million USD non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 90-day LIBOR plus a margin. On May 22, 2020, proceeds from this loan were used to repay $22 million USD senior notes upon maturity.

On May 20, 2020, GBPC entered into a $15 million BSD ($15 million USD) non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 4.00 per cent.

At December 31, 2020, BLPC had drawn $77 million BBD ($38 million USD) against a $110 million BBD ($55 million USD) non-revolving term loan. The loan bears interest at a rate of 2.05 per cent and has a 5-year term.

Gas Utilities and Infrastructure

On February 5, 2021, NMGC completed an issuance of $220 million USD senior notes. The issuance included $70 million USD senior notes that bear interest at a rate of 2.26 per cent with a maturity date of February 5, 2031, $65 million USD senior notes that bear interest at a rate of 2.51 per cent and with a maturity date of February 5, 2036, and $85 million USD senior notes that bear interest at a rate of 3.34 per cent with a maturity date of February 5, 2051. Proceeds from this issuance were used to repay a $200 million USD note, due in 2021 and for general corporate purposes. These notes were classified as long-term debt at December 31, 2020.

On December 18, 2020, NMGC amended and restated its $125 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $30 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Other

On February 28, 2020, TECO Finance extended the maturity date of its $500 million USD credit facility from March 5, 2020 to July 3, 2020. There were no other significant changes in commercial terms from the prior agreement. Using funds from the sale of Emera Maine, on April 3, 2020, TECO Finance repaid $200 million USD of the term loan and the remaining $300 million USD was repaid on June 30, 2020.

On March 13, 2020, TECO Finance repaid a $300 million USD note upon maturity. The note was repaid using existing credit facilities.

On December 1, 2020, Emera extended the maturity date of its $400 million non-revolving term loan from December 15, 2020 to December 16, 2021. There were no other significant changes in commercial terms from the prior agreement.

On December 18, 2020, TECO Finance amended and restated its $400 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The facility now includes a $50 million USD letter of credit facility. 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- (Stable)	Baa3 (Stable)	N/A
TECO Energy/TECO Finance	N/A	BBB- (Stable)	Baa1 (Positive)	N/A
TEC	A (Stable)	BBB+ (Stable)	A3 (Positive)	N/A
NMGC	BBB+ (Stable)	N/A	N/A	N/A
NSPI	N/A	BBB+ (Stable)	N/A	A (low) (Stable)

On December 21, 2020, Moody's Investor Services upgraded its senior unsecured bank credit rating on TECO Energy to Baa1 from Baa2. Moody's also affirmed TEC's A3 senior unsecured rating. The rating outlook remains positive.

On July 8, 2020, Fitch Ratings assigned a first-time long-term issuer default rating of BBB+ to NMGC. The rating outlook is stable.

On March 24, 2020, S&P changed its issuer rating for Emera and TECO to BBB from BBB+ and at the same time changed the outlook on both to stable from negative. S&P also affirmed its BBB+ issuer ratings for TEC and NSPI and changed the outlook on both to stable from negative.

SHARE CAPITAL

Emera

As at December 31, 2020, Emera had 251.43 million (2019 – 242.48 million) common shares issued and outstanding. For the year ended December 31, 2020, 8.95 million common shares were issued (2019 – 8.36 million) for net proceeds of $489 million (2019 – $400 million).

As at December 31, 2020, Emera had 41 million preferred shares issued and outstanding (2019 – 41 million).

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. The cash required in 2021 for defined benefit pension plans is expected to be $41 million (2020 – $41 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic and global bonds and short-term investments. Emera reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

Emera's projected contributions to defined contribution pension plans, are $44 million for 2021 (2020 – $45 million).

DEFINED BENEFIT PENSION PLAN SUMMARY

millions of Canadian dollars

Plans by region	TECO Energy	NSPI	Maine (1)	Caribbean	Total
Assets as at December 31, 2020	$ 1,150	$ 1,445	$ –	$ 10	$ 2,605
Accounting obligation at December 31, 2020	1,168	1,576	–	15	2,759
Accounting expense during fiscal 2020	$ 19	$ 7	$ 1	$ 1	$ 28

(1) On March 24, 2020, Emera completed the sale of Emera Maine.

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, 2020 totalled $582 million (2019 – $740 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 78 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, 2020:

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.

Emera Inc. has issued a guarantee of up to $35 million USD relating to outstanding notes of GBPC. The guarantee for the notes will expire in May 2023.

NSPI has issued guarantees in the amount of $18 million USD on behalf of its subsidiary, NS Power Energy Marketing Incorporated ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers. The guarantees have terms of varying lengths and will be renewed as required.

The Company has standby letters of credit and surety bonds in the amount of $55 million USD (December 31, 2019 – $82 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 expiry date of this letter of credit was extended to June 2021. The amount committed as at December 31, 2020 was $63 million (December 31, 2019 – $52 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 through and beyond the forecast period, it is expected to return to that range over time. Emera Incorporated's common share dividends paid in 2020 were $2.4750 ($0.6125 in Q1, Q2, and Q3 and $0.6375 in Q4) per common share and $2.3750 ($0.5875 in Q1, Q2, and Q3 and $0.6125 in Q4) per common share for 2019, representing a payout ratio of 91 per cent of adjusted net income in 2020 and 91 per cent in 2019.

On September 16, 2020, Emera's Board of Directors approved an increase in the annual common share dividend rate to $2.55 from $2.45. The first quarterly dividend payment at the increased rate was paid on November 16, 2020.

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 $139 million for the year ended December 31, 2020 (2019 – $107 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.

For further details, refer to the "Business Overview and Outlook – Canadian Electric Utilities – ENL" and "Contractual Obligations" sections.

- 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 $18 million for the year ended December 31, 2020 (2019 – $63 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, 2020 and at December 31, 2019.

ENTERPRISE RISK AND RISK MANAGEMENT

Emera has a business-wide risk management process, overseen by its Enterprise Risk Management Committee and monitored by the Board of Directors, to ensure an effective, 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 subject to appropriate controls and, in the case of certain credit risks, controlled within predetermined financial risk tolerances established through approved policies.

The Company's financial risk management activities are focused on those areas that most significantly impact profitability, quality and consistency of income, and cash flow. Emera's risk management focus extends to key operational risks including safety and environment, which represent core values of Emera. In this section, Emera describes the 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. Regulatory and political risk can include change in regulatory frameworks, shifts in government policy, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. 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. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, M&NP and Lucelec. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement expiring in 2034, with Repsol Energy Canada ("REC"). The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract.

Changes in government and shifts in government policy can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect operations, net income and cash flows. Recently state and local policies in some US jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas. Changes in applicable state or local laws and regulations could adversely impact PGS and NMGC.

Emera's rate-regulated subsidiaries are subject to regulatory processes. 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, regulatory audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

GLOBAL CLIMATE CHANGE RISK

The Company is subject to risks that may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon emissions. Municipal, 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 decarbonization initiatives and promotion of cleaner energy and renewable energy generation of electricity. Refer to "Changes in Environmental Legislation" risk below. 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".

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 in Florida, solar generation and the modernization of the Big Bend Power Station. Tampa Electric has taken significant steps to reduce overall emissions at its facilities. Tampa Electric expects to achieve a 45 per cent reduction in GHG emissions compared to 2005 levels by 2023 as a result of its investment in solar and natural gas generation which will reduce coal generation. 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 expects to achieve compliance with a provincially mandated target of at least 40 per cent of energy generated from renewable sources over the 2020-to-2022 period. Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. NSPI continues to work with both the provincial and federal governments on measures to address their carbon reduction goals. 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 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 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" for further information.

These risks are mitigated to an extent through features such as flood walls at certain plants and through the location of plants on higher ground. Planned investments in under-grounding parts of the electricity infrastructure contributes to risk mitigation, as does insurance coverage (for assets other than electricity transmission and distribution assets). In addition, implementation of regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts help to smooth out the recovery of storm restoration costs 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, delivery delays and 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. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation" risk. The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition 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 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 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 hydroelectric generation 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 which may be 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 influence 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 and storm surge could adversely affect the operations of utilities and in particular generation assets.

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. If not recovered through these means, they 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 regarding 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. Legislative or regulatory 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 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 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. An outbreak of infectious disease, a pandemic or a similar public health threat, such as COVID-19, may cause disruption in normal working patterns including wide scale "work from home" policies, which could increase cybersecurity risk as the quantity of both cyberattacks and network interfaces increases. Refer to the "Public Health Risk" section below. 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, that are described below, 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, strategy derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework, and employee communication and training. 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.

PUBLIC HEALTH RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company, including causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business.

The extent of the evolving COVID-19 pandemic and its future impact on the Company is uncertain. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat. The Company's top priority continues to be the health and safety of its customers and employees.

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

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 could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions 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 and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions including those related to public health threats, such as the COVID-19 pandemic.

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. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks 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.

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 interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Interest rates may be impacted by market disruptions related to public health threats, including the COVID-19 pandemic.

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.

PROJECT DEVELOPMENT AND LAND USE RIGHTS RISK

The Company's capital plan includes significant investment in generation, infrastructure modernization and customer-focused technologies. Any projects planned or currently in construction, particularly significant capital projects, may be subject to risks including, but not limited to, impact on costs from schedule delays, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial, state, regional and local levels. There is no assurance that Emera will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

Some of the Company's assets are located on land owned by third parties, including Indigenous Peoples, and may be subject to land claims. Present or future assets may be located on lands that have been used for traditional purposes and therefore subject to specific consultations, consents, or conditions for development or operation. If the Company's rights to locate and operate its assets on any such lands are subject to expiry or become invalid, it may incur material costs to renew rights or obtain such rights. If reasonable terms for land-use rights cannot be negotiated, the Company may incur significant costs to remove and relocate its assets and restore the land. Additional costs incurred could cause projects to be uneconomical to proceed with.

Emera manages these project development and land use rights risks by deploying robust project and risk management approaches, led by teams with extensive experience in large projects. The Company consults with Indigenous Peoples in obtaining approvals, constructing, maintaining and operating such facilities, consistent with laws and public policy frameworks. Emera maintains relationships through on-going communications with stakeholders, including Indigenous Peoples, landowners and governments.

COUNTERPARTY RISK

Emera is exposed to risk related to its reliance on certain key partners, suppliers, and customers, any of which may endure financial challenges resulting from commodity price and market volatility, economic instability or adversity, adverse political or regulatory changes and other causes which may cause or contribute to such parties' insolvency, bankruptcy, restructuring or default on their contractual obligations to Emera. 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. Counterparty creditworthiness and the ability of key partners, suppliers and customers to perform their contractual obligations may be affected by economic impacts related to COVID-19.

Emera manages this counterparty risk through contractual rights and remedies, regulatory frameworks and 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 may be requested on certain accounts. Emera may also seek recovery of unpaid amounts or damages through applicable bankruptcy, insolvency or similar proceedings.

COUNTRY RISK

Earnings outside of Canada constituted 73 per cent of Emera's earnings in 2020 (2019 – 61 per cent) with the majority from the US. 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

The Company's utility fuel supply is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments are all used to manage and mitigate this risk. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

Regulated Utilities

A large portion of the Company's utility fuel supply comes from international suppliers and therefore 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 using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated utilities have adopted and implemented fuel adjustment mechanisms which has further helped manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Emera Energy Marketing and Trading

Emera Energy has employed further measures to manage commodity risk. 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.

FUTURE EMPLOYEE BENEFIT PLAN PERFORMANCE AND FUNDING RISK

Emera subsidiaries have both defined benefit and defined contribution employee pension plans that cover their employees and retirees. All defined benefit plans are closed to new entrants, except for 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. The COVID-19 pandemic could have an impact on key actuarial assumptions. 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 three to five 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 35 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's digital transformation strategy, including investment in infrastructure modernization and customer focused technologies, is driving increased investment in information technology solutions, resulting in increased project risks associated with the implementation of these solutions.

Emera manages these information technology risks 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, change management 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 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 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 an updated risk dashboard and heat map quarterly for the Board of Directors. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

The Company manages 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 millions of Canadian dollars	**December 31 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 1**	$ –
Derivative instrument liabilities (current and long-term liabilities)	**–**	(1)
Net derivative instrument assets (liabilities)	**$ 1**	$ (1)

HEDGING IMPACT RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2020	2019
Operating revenues – regulated	**$ (2)**	$ (3)
Effective net losses	**$ (2)**	$ (3)

The effective net losses reflected in the above table are offset in net income by the hedged item realized in the period.

REGULATORY ITEMS RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 14**	$ 28
Regulatory assets (current and other assets)	**65**	80
Derivative instrument liabilities (current and long-term liabilities)	**(62)**	(78)
Regulatory liabilities (current and long-term liabilities)	**(15)**	(42)
Net asset (liability)	**$ 2**	$ (12)

REGULATORY IMPACT RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2020	2019
Regulated fuel for generation and purchased power (1)	**$ (21)**	$ 5
Net gains (losses)	**$ (21)**	$ 5

(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 millions of Canadian dollars	**December 31 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 68**	$ 58
Derivative instrument liabilities (current and long-term liabilities)	**(275)**	(291)
Net derivative instrument liability	**$ (207)**	$ (233)

HFT ITEMS RECOGNIZED IN NET INCOME

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

For the millions of Canadian dollars		Year ended December 31
	2020	2019
Non-regulated operating revenues	**$ 204**	$ 282
Non-regulated fuel for generation and purchased power	**(4)**	(6)
Net gains	**$ 200**	$ 276

OTHER DERIVATIVES RECOGNIZED ON THE BALANCE SHEETS

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

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Derivative instrument assets (current and other assets)	**$ 15**	$ 1
Derivative instrument liabilities (current and long-term liabilities)	**(1)**	–
Net derivative instrument assets	**$ 14**	$ 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 millions of Canadian dollars		Year ended December 31
	2020	2019
Operating, maintenance and general	**$ (4)**	$ 28
Other income, net	**13**	–
Net gains	**$ 9**	$ 28

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, 2020 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 year ended December 31, 2020, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

Preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting periods. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized through income in the year they arise.

During the year ended December 31, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis these unfavourable impacts have not had a material financial impact on 2020 net earnings. This was primarily due to a favourable change to the mix of sales across customer classes resulting in the lower commercial and industrial sales being partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather in 2020, in particular in Florida, has further reduced the consolidated impact. Emera's utilities provide essential services and continue to operate and meet customer demand. Governments world-wide have implemented measures intended to address the pandemic. These measures include travel and transportation restrictions, quarantines, physical distancing, closures of commercial spaces and industrial facilities, shutdowns, shelter-in-place orders and other health measures. These measures are adversely impacting global, national and local economies. In addition, Global equity markets have experienced significant volatility. Governments and central banks are implementing measures designed to stabilize economic conditions. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and judgments and concluded that no material adjustments were required at December 31, 2020. The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted and will depend on future developments, including duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. 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. 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 $1,584 million (2019 – $1,552 million) of regulatory assets and $1,961 million (2019 – $2,181 million) of regulatory liabilities as at December 31, 2020.

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. 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 $866 million at December 31, 2020 (2019 – $891 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 expectations.

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. The COVID-19 pandemic could have an impact on key actuarial assumptions. 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 annual funding requirements. This could have a significant impact on the Company's annual earnings and 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 9.4 years (9.8 years for 2020 benefit cost) for the Canadian plans and a weighted average of 12.1 years for the US plans). The Company's use of smoothed asset values reduces 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:

		2020		2019
	Discount rate for benefit cost purposes	**Expected return on plan assets**	Discount rate for benefit cost purposes	Expected return on plan assets
TECO Energy Group Retirement Plan	**3.22%**	**7.00%**	4.34% / 3.13%	7.35% / 7.00%
TECO Energy Group Supplemental Executive Retirement Plan (1)	**2.78%**	**N/A**	4.02%	N/A
TECO Energy Group Benefit Restoration Plan (1)	**2.81%**	**N/A**	4.12% / 3.94% / 3.32%	N/A
TECO Energy Post-retirement Health and Welfare Plan	**3.32%**	**N/A**	4.38%	N/A
New Mexico Gas Company Retiree Medical Plan	**3.32%**	**3.25%**	4.39%	3.25%
NSPI	**3.13%, 3.21%**	**5.75%**	3.83%	6.00%
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) On March 24, 2020, Emera completed the sale of Emera Maine. The discount rate for benefit cost purposes and expected return on plan assets up until the time of sale was 3.18% (2019 – 4.19%) and 6.35% (2019 – 6.35%) for Bangor Hydro and 3.09% (2019 – 4.12%) and 6.55% (2019 – 6.55%) for Maine Public Service.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $87 million in 2020 (2019 – $84 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 2020 benefit cost of $6 million and $5 million respectively (2019 – $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 other Emera utilities. 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, 2020, unbilled revenues totalled $286 million (2019 – $265 million) on total regulated operating revenues of $5,476 million (2019 – $5,850 million).

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 63 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 depreciation studies and require 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 $860 million for the year ended December 31, 2020 (2019 – $881 million).

GOODWILL IMPAIRMENT ASSESSMENTS

Goodwill is subject to an annual assessment for impairment at the reporting unit level with interim impairment tests performed when impairment indicators are present. 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 on significant assumptions and estimates. 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 the Company 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 the Company 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 include discount and growth rates, rate case assumptions, valuation of the reporting units' net operating loss ("NOL"), utility sector market performance and transactions, projected operating and capital cash flows and the fair value of debt. As part of the 2020 goodwill impairment assessment management considered potential impacts of the COVID-19 pandemic on future earnings of the reporting units.

As of December 31, 2020, the Company had goodwill with a total carrying amount of $5,720 million (December 31, 2019 – $5,835 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 identifiable assets acquired and liabilities assumed. The change in the carrying value of goodwill from 2019 to 2020 was a result of the strengthening Canadian dollar on the goodwill balances.

As of December 31, 2020, $5,649 million of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). A qualitative assessment was performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded that it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required.

A GBPC 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. As of December 31, 2020, $68 million of Emera's goodwill was related to GBPC. In Q4 2020, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in forecasted future earnings due to limited excess of fair value over the carrying value. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions could result in a future impairment. For further detail, refer to note 22 to the consolidated financial statements.

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 the sale of a business. 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 they 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 regarding 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 consider external factors and market forces, as of the end of each reporting period. Assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at December 31, 2020, there were no indications of impairment of Emera's long-lived assets. The impact of COVID-19 could cause the Company to impair long-lived assets in the future; however, there is currently no indication that future cash flows would be impacted to a point where the Company's long-lived assets would not be recoverable.

In Q1 2020, impairment charges of $25 million ($26 million after tax) were recognized on certain assets and recorded in Impairment Charge on the Consolidated Income Statement. In 2019, as a result of Hurricane Dorian, Grand Bahama recognized an impairment of $18 million USD which has been fully recovered through insurance.

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 application of tax statutes and regulations and the outcomes of tax audits and appeals, requires that 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 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. 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")

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, 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 expense". 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, 2020, AROs recorded on the balance sheet were $178 million (2019 – $185 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $432 million (2019 – $422 million), which will be incurred between 2021 and 2061. The majority of these costs will be incurred between 2028 and 2050.

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 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 2020, are described as follows:

MEASUREMENT OF CREDIT LOSSES ON FINANCIAL INSTRUMENTS

The Company adopted Accounting Standard Update ("ASU") 2016-13, *Measurement of Credit Losses on Financial Instruments* effective January 1, 2020. 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. These include 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 adoption of the standard resulted in a $7 million decrease to retained earnings in the consolidated financial statements as of January 1, 2020.

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. It also 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 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard is applied on both a prospective and retrospective basis. The Company early adopted the standard effective January 1, 2020. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

FACILITATION OF THE EFFECTS OF REFERENCE RATE REFORM ON FINANCIAL REPORTING

The Company adopted ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* in Q4 2020. The standard provides options and exceptions for applying USGAAP to contract modifications and hedging relationships that reference the London Inter-Bank Offered Rate ("LIBOR") or any other reference rate that is expected to be discontinued. The guidance was effective as of the date of issuance and entities may elect to apply the guidance prospectively through December 31, 2022. The Company's transition from reference rates will not have a material impact on the consolidated financial statements. In November 2020, the Federal Reserve extended the phase-out of LIBOR until June 2023. The Company will continue to monitor the impact this may have on application of the 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 as allowed, 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.

ACCOUNTING FOR CONVERTIBLE INSTRUMENTS AND CONTRACTS IN AN ENTITY'S OWN EQUITY

In August 2020, the FASB issued ASU 2020-06, Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40). The standard simplifies the accounting for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2021. Early adoption is permitted, but no earlier than fiscal years beginning after December 15, 2020. The standard can be applied through either a modified retrospective method of transition or a fully retrospective method of transition. The Company early adopted the standard effective January 1, 2021 using the modified retrospective method. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

GUARANTEED DEBT SECURITIES DISCLOSURE REQUIREMENTS

In October 2020, the FASB issued ASU 2020-09, Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762. The change in the standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying disclosure, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. The guidance will be effective for annual reports filed for fiscal years ending after January 4, 2021, with early adoption permitted. 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 millions of Canadian dollars (except per share amounts)	**Q4 2020**	**Q3 2020**	**Q2 2020**	**Q1 2020**	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Operating revenues	**$ 1,537**	**$ 1,163**	**$ 1,169**	**$ 1,637**	$ 1,616	$ 1,299	$ 1,378	$ 1,818
Net income attributable to common shareholders	**273**	**84**	**58**	**523**	193	55	103	312
Adjusted net income attributable to common shareholders	**188**	**166**	**118**	**193**	145	122	130	224
Earnings per common share – basic	**1.09**	**0.34**	**0.24**	**2.14**	0.79	0.23	0.43	1.32
Earnings per common share – diluted	**1.08**	**0.34**	**0.23**	**2.13**	0.80	0.23	0.43	1.32
Adjusted earnings per common share – basic	**0.75**	**0.67**	**0.48**	**0.79**	0.60	0.51	0.54	0.95

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 demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the "Significant Items Affecting Earnings" section. In 2020, quarterly results include the impact of the COVID-19 pandemic commencing in March 2020. For further detail, refer to the "Business Overview and Outlook" 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 judgments 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 16, 2021

"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, 2020 and 2019, 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, 2020 and 2019, 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.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

	Accounting for the effects of rate regulation
Key Audit Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $1.6 billion in regulatory assets and $2.0 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including property, plant and equipment, operating revenues and expenses, income taxes, and depreciation expense. Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and recovery on costs incurred, of the disallowance of part of the cost of recently completed property, plant and equipment and construction work in progress, or of the probable refund to customers through future rates.

	Accounting for the effects of rate regulation
How Our Audit Addressed the Key Audit Matter	We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.
	Fair value measurement and disclosure of derivative financial instruments
Key Audit Matter	Held-for-trading ("HFT") derivative assets of $152 million and liabilities of $359 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized $200 million in realized and unrealized gains during the year with respect to HFT derivatives. Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials, the Company's own credit risk and discount rates. These assumptions have a significant impact on the fair value of the HFT derivatives.
How Our Audit Addressed the Key Audit Matter	We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves, credit metrics and discount rates used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the fair value hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the fair value of derivatives.

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 reports 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.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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

Ernst & Young LLP

Chartered Professional Accountants

Halifax, Canada
February 16, 2021

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, 2020 and 2019, 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, 2020 and 2019, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2020, 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 audits. 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 included 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

	Accounting for the effects of rate regulation
Description of the Matter	As disclosed in note 7 of the consolidated financial statements, the Company has $1.6 billion in regulatory assets and $2.0 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including property, plant and equipment, operating revenues and expenses, income taxes, and depreciation expense. Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and recovery on costs incurred, of the disallowance of part of the cost of recently completed property, plant and equipment and construction work in progress, or of the probable refund to customers through future rates.
How We Addressed the Matter in Our Audit	We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, property, plant and equipment, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation.

Fair value measurement and disclosure of derivative financial instruments

Description of the Matter

Held-for-trading ("HFT") derivative assets of $152 million and liabilities of $359 million, disclosed in note 15 to the consolidated financial statements, are measured at fair value. The Company recognized $200 million in realized and unrealized gains during the year with respect to HFT derivatives.

Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the fair value of the contracts. In determining the fair value of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials, the Company's own credit risk and discount rates. These assumptions have a significant impact on the fair value of the HFT derivatives.

How We Addressed the Matter in Our Audit

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves, credit metrics and discount rates used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the fair value hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the fair value of derivatives.

Ernst & Young LLP

Chartered Professional Accountants

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

Halifax, Canada
February 16, 2021

Emera Incorporated

CONSOLIDATED STATEMENTS OF INCOME

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 **2020**	2019
Operating revenues		
Regulated electric	**$ 4,442**	$ 4,769
Regulated gas	**1,034**	1,081
Non-regulated	**30**	261
Total operating revenues (note 6)	**5,506**	6,111
Operating expenses		
Regulated fuel for generation and purchased power (notes 17 and 19)	**1,420**	1,609
Regulated cost of natural gas	**293**	350
Non-regulated fuel for generation and purchased power	**4**	66
Operating, maintenance and general	**1,419**	1,464
Provincial, state, and municipal taxes	**317**	342
Depreciation and amortization	**881**	903
Impairment charges	**25**	34
Total operating expenses	**4,359**	4,768
Income from operations	**1,147**	1,343
Income from equity investments (note 8)	**149**	154
Other income, net (note 9)	**708**	12
Interest expense, net	**679**	738
Income before provision for income taxes	**1,325**	771
Income tax expense (note 10)	**341**	61
Net income	**984**	710
Non-controlling interest in subsidiaries	**1**	2
Preferred stock dividends	**45**	45
Net income attributable to common shareholders	**$ 938**	$ 663
Weighted average shares of common stock outstanding (in millions) (note 12)		
Basic	**248**	240
Diluted	**248**	240
Earnings per common share (note 12)		
Basic	**$ 3.78**	$ 2.76
Diluted	**$ 3.78**	$ 2.76
Dividends per common share declared	**$ 2.4750**	$ 2.3750

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

Emera Incorporated

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the millions of Canadian dollars	Year ended December 31 2020	 2019
Net income	**$ 984**	$ 710
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**(201)**	(402)
Unrealized gains on net investment hedges (2) (3)	**26**	78
Cash flow hedges		
Net derivative gains	**–**	3
Less: reclassification adjustment for losses included in income	**2**	3
Net effects of cash flow hedges	**2**	6
Net change in unrecognized pension and post-retirement benefit obligation (4)	**(1)**	74
Other comprehensive income (loss) (5)	**(174)**	(244)
Comprehensive income (loss)	**810**	466
Comprehensive income (loss) attributable to non-controlling interest	**1**	1
Comprehensive Income (loss) of Emera Incorporated	**$ 809**	$ 465

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

(1) Net of tax recovery of $1 million (2019 – nil) for the year ended December 31, 2020.
(2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.
(3) Net of tax expense of $4 million (2019 – $1 million tax expense) for the year ended December 31, 2020.
(4) Net of tax recovery of $1 million (2019 – $9 million expense) for the year ended December 31, 2020.
(5) Net of tax expense of $2 million (2019 – $10 million expense) for the year ended December 31, 2020.

Emera Incorporated

CONSOLIDATED BALANCE SHEETS

As at millions of Canadian dollars	December 31 2020	December 31 2019
Assets		
Current assets		
Cash and cash equivalents	**$ 220**	$ 222
Restricted cash (note 32)	**34**	51
Inventory (note 14)	**453**	467
Derivative instruments (notes 15 and 16)	**73**	54
Regulatory assets (note 7)	**165**	121
Receivables and other current assets (note 18)	**1,233**	1,486
Assets held for sale (note 4)	**–**	85
	2,178	2,486
Property, plant and equipment, net of accumulated depreciation and amortization of $8,714 and $8,317, respectively (note 20)	**19,535**	18,167
Other assets		
Deferred income taxes (note 10)	**209**	186
Derivative instruments (notes 15 and 16)	**25**	33
Regulatory assets (note 7)	**1,419**	1,431
Net investment in direct financing lease (note 19)	**475**	473
Investments subject to significant influence (note 8)	**1,346**	1,312
Goodwill (note 22)	**5,720**	5,835
Other long-term assets	**327**	300
Assets held for sale (note 4)	**–**	1,619
	9,521	11,189
Total assets	**$ 31,234**	$ 31,842

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

Emera Incorporated

CONSOLIDATED BALANCE SHEETS (continued)

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Liabilities and Equity		
Current liabilities		
Short-term debt (note 23)	**$ 1,625**	$ 1,537
Current portion of long-term debt (note 25)	**1,382**	501
Accounts payable	**1,148**	1,118
Derivative instruments (notes 15 and 16)	**251**	268
Regulatory liabilities (note 7)	**129**	295
Other current liabilities (note 24)	**340**	333
Liabilities associated with assets held for sale (note 4)	**–**	114
	4,875	4,166
Long-term liabilities		
Long-term debt (note 25)	**12,339**	13,679
Deferred income taxes (note 10)	**1,629**	1,285
Derivative instruments (notes 15 and 16)	**87**	102
Regulatory liabilities (note 7)	**1,832**	1,886
Pension and post-retirement liabilities (note 21)	**453**	460
Other long-term liabilities (notes 8 and 26)	**781**	764
Long-term liabilities associated with assets held for sale (note 4)	**–**	899
	17,121	19,075
Equity		
Common stock (note 11)	**6,705**	6,216
Cumulative preferred stock (note 28)	**1,004**	1,004
Contributed surplus	**79**	78
Accumulated other comprehensive income (loss) (note 13)	**(79)**	95
Retained earnings	**1,495**	1,173
Total Emera Incorporated equity	**9,204**	8,566
Non-controlling interest in subsidiaries (note 29)	**34**	35
Total equity	**9,238**	8,601
Total liabilities and equity	**$ 31,234**	$ 31,842

Commitments and contingencies (note 27)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Year ended December 31 **2020**	2019
Operating activities		
Net income	**$ 984**	$ 710
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**899**	911
Income from equity investments, net of dividends	**(76)**	(83)
Allowance for equity funds used during construction	**(45)**	(21)
Deferred income taxes, net	**381**	125
Net change in pension and post-retirement liabilities	**(23)**	(17)
Regulated fuel adjustment mechanism	**(94)**	(46)
Net change in fair value of derivative instruments	**(36)**	(39)
Net change in regulatory assets and liabilities	**(87)**	44
Net change in capitalized transportation capacity	**52**	(55)
Impairment charges	**25**	34
Gain on sale, excluding transaction costs	**(603)**	–
Other operating activities, net	**43**	35
Changes in non-cash working capital (note 30)	**217**	(73)
Net cash provided by operating activities	**1,637**	1,525
Investing activities		
Additions to property, plant and equipment	**(2,623)**	(2,495)
Proceeds from dispositions (note 4)	**1,401**	875
Other investing activities	**(2)**	3
Net cash used in investing activities	**(1,224)**	(1,617)
Financing activities		
Change in short-term debt, net	**385**	413
Proceeds from short-term debt with maturities greater than 90 days	**399**	–
Repayment of short-term debt with maturities greater than 90 days	**(688)**	–
Proceeds from long-term debt, net of issuance costs	**428**	1,066
Retirement of long-term debt	**(513)**	(1,103)
Net repayments under committed credit facilities	**(203)**	(118)
Issuance of common stock, net of issuance costs	**285**	203
Dividends on common stock	**(409)**	(378)
Dividends on preferred stock	**(45)**	(45)
Other financing activities	**(11)**	(24)
Net cash (used in) provided by financing activities	**(372)**	14
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(61)**	(20)
Net decrease in cash, cash equivalents, restricted cash and assets held for sale	**(20)**	(98)
Cash, cash equivalents, restricted cash, and assets held for sale, beginning of year	**274**	372
Cash, cash equivalents, and restricted cash, end of year	**$ 254**	$ 274
Cash, cash equivalents, restricted cash and assets held for sale consists of:		
Cash	**$ 220**	$ 222
Restricted cash	**34**	51
Assets held for sale	**–**	1
Cash, cash equivalents and restricted cash	**$ 254**	$ 274

Supplementary Information to Consolidated Statements of Cash Flows (note 30)

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, 2019	**$ 6,216**	**$ 1,004**	**$ 78**	**$ 95**	**$ 1,173**	**$ 35**	**$ 8,601**
Net income of Emera incorporated	**–**	**–**	**–**	**–**	**983**	**1**	**984**
Other comprehensive loss, net of tax expense of $2 million	**–**	**–**	**–**	**(174)**	**–**	**–**	**(174)**
Dividends declared on preferred stock (note 28)	**–**	**–**	**–**	**–**	**(45)**	**–**	**(45)**
Dividends declared on common stock ($2.4750/share)	**–**	**–**	**–**	**–**	**(609)**	**–**	**(609)**
Common stock issued under purchase plan	**215**	**–**	**–**	**–**	**–**	**–**	**215**
Issuance of common stock, net of after-tax issuance costs	**251**	**–**	**–**	**–**	**–**	**–**	**251**
Senior management stock options exercised	**20**	**–**	**(1)**	**–**	**–**	**–**	**19**
Adoption of credit losses accounting standard (note 2)	**–**	**–**	**–**	**–**	**(7)**	**–**	**(7)**
Other	**3**	**–**	**2**	**–**	**–**	**(2)**	**3**
Balance, December 31, 2020	**$ 6,705**	**$ 1,004**	**$ 79**	**$ (79)**	**$ 1,495**	**$ 34**	**$ 9,238**
Balance, December 31, 2018	$ 5,816	$ 1,004	$ 84	$ 338	$ 1,075	$ 41	$ 8,358
Net income	–	–	–	–	708	2	710
Other comprehensive loss, net of tax expense of $10 million	–	–	–	(243)	–	(1)	(244)
Dividends declared on preferred stock (note 28)	–	–	–	–	(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 29)	–	–	–	–	–	14	14
Redemption of preferred shares of GBPC (note 29)	–	–	–	–	–	(19)	(19)
Other	2	–	1	–	–	(2)	1
Balance, December 31, 2019	$ 6,216	$ 1,004	$ 78	$ 95	$ 1,173	$ 35	$ 8,601

(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, 2020 and 2019

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

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

At December 31, 2020, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility, serving approximately 792,500 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 529,000 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. 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 45.6 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. In response to the COVID-19 pandemic, on March 17, 2020 Nalcor announced that it had paused construction activities at the Muskrat Falls site and resumed work in May 2020. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing project commissioning in 2021. Refer to note 27 for further details.
- Other Electric Utilities, which includes 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 19,000 customers;
  - 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 34,000 customers; and
  - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

On March 24, 2020, Emera completed the sale of Emera Maine which was previously included in the Other Electric Utilities segment. Refer to note 4 for further information.

- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System ("PGS"), a regulated gas distribution utility, serving approximately 426,000 customers across Florida;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 540,000 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.
- Emera's other reportable segment includes investments in energy-related non-regulated companies which includes:
  - 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 Emera Energy's New England Gas Generating ("NEGG") and Bayside facilities, and Emera Utility Services ("EUS") equipment and inventory.

In 2020, the outbreak of the novel strain of coronavirus, specifically identified as COVID-19, has resulted in governments worldwide enacting emergency measures to combat the spread of the virus. While management considered the impact of COVID-19 in the Company's estimates and results, the financial statements as of and for the year ended December 31, 2020 were not materially impacted by COVID-19. However, it is not possible to reliably estimate the length and severity of the COVID-19 pandemic and the impact on the financial results and condition of the Company in future periods.

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 32 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. 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.

Intercompany balances and 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. Significant areas requiring the use of management estimates relate to rate-regulated assets and liabilities, allowance for credit losses, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected 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.

During the year ended December 31, 2020, the ongoing COVID-19 pandemic has affected all service territories in which Emera operates. The pandemic has generally resulted in lower load and higher operating costs than what otherwise would have been experienced at the Company's utilities. Some of Emera's utilities have been impacted more than others. However, on a consolidated basis these unfavourable impacts have not had a material financial impact to net earnings primarily due to a favourable change to the mix of sales across customer classes. Lower commercial and industrial sales have been partially offset by increased sales to residential customers, which have a higher contribution to fixed cost recovery. Favourable weather in 2020, particular in Florida, has further reduced the consolidated impact. Emera's utilities provide essential services and continue to operate and meet customer demand. Governments world-wide have implemented measures intended to address the pandemic. These measures include travel and transportation restrictions, quarantines, physical distancing, closures of commercial spaces and industrial facilities, shutdowns, shelter-in-place orders and other health measures. These measures are adversely impacting global, national and local economies. Global equity markets have experienced significant volatility. Governments and central banks are implementing measures designed to stabilize economic conditions. The pace and strength of economic recovery is uncertain and may vary among jurisdictions.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments are required for the year ended December 31, 2020. Refer to Asset Impairment: Long-Lived Assets, Asset Impairment: Goodwill and Employee Benefits below for additional details on area's that could be more significantly impacted.

The extent of future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time and will depend on future developments, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further potential government actions and future economic activity and energy usage. 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 prudently incurred costs of providing the regulated products or services and provide an opportunity for a reasonable rate of return on the equity invested or assets, as applicable (refer to note 7 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 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 margins are 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, except for 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.

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 labour 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 and land rights. 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. 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 identifiable 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 assessment for impairment at the reporting unit level annually or if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. Refer to note 22 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. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change is enacted unless required to be offset to a regulatory asset or liability by law or by order of the regulator. 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 and NMGC on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by regulatory practices.

Tampa Electric, PGS, NMGC, BLPC and Domlec collect income taxes from customers based on current and deferred income taxes. NSPI, ENL and Brunswick Pipeline collect income taxes from customers based on income tax that is currently payable except for the deferred income taxes on certain regulatory balances specifically prescribed by the regulator. For the balance of regulated deferred income taxes, NSPI, ENL and Brunswick Pipeline recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. 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. GBPC is not subject to income taxes.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. Refer to note 10 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. 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 derivative transactions is recognized as an asset in "Receivables and other current assets" 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.

RECEIVABLES AND ALLOWANCE FOR CREDIT LOSSES

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 on accounts in accordance with the Company's policy. The Company also maintains provisions for expected credit losses, which are assessed on a regular basis.

Management estimates credit losses related to accounts receivable after considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit 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.

The economic impact of COVID-19, in the service territories in which Emera operates, has impacted the aging of customer receivables resulting in higher allowances for credit losses related to customer receivables however it has not had a material impact on earnings.

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.

Management considered whether the potential impacts of the COVID-19 pandemic on undiscounted future cash flows could indicate that long-lived assets are not recoverable. As at December 31, 2020, there are no indications of impairment of Emera's long-lived assets. The impact of COVID-19 could cause the Company to impair long-lived assets in the future; however, there is currently no indication that future cash flows would be impacted to a point where the Company's long-lived assets would not be recoverable.

Impairment charges of $25 million ($26 million after tax) were recognized on certain assets during the year ended December 31, 2020 and recorded in Impairment Charge in the Consolidated Income Statement. In 2019, as a result of Hurricane Dorian, Grand Bahama recognized an impairment of $18 million USD which has been fully recovered through insurance.

Goodwill

Goodwill is not amortized but is subject to an annual assessment for impairment at the reporting unit level with interim impairment tests performed when impairment indicators are present. 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. When assessing goodwill for impairment the Company has 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 the Company 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 the Company 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 reporting unit'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 the reporting unit'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. As part of the 2020 goodwill impairment assessment management considered the potential impacts of the COVID-19 pandemic on the future earnings of the reporting units.

As of December 31, 2020, $5,649 million of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Qualitative assessments were performed for these reporting units given the significant excess of fair value over carrying amounts calculated during the last quantitative test in Q4 2019. Management concluded that it was more likely than not that the fair value of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required.

A GBPC 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. As of December 31, 2020, $68 million of Emera's goodwill was related to GBPC. In Q4 2020, the Company performed a quantitative impairment assessment for GBPC as this reporting unit is more sensitive to changes in forecasted future earnings due to limited excess of fair value over the carrying value. The assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions could result in a future impairment. Refer to note 22 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, including the impact of COVID-19. 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 2019 or 2020.

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 impairment of financial assets was required for either 2019 or 2020.

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.

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.

The COVID-19 pandemic could impact key actuarial assumptions used to account for employee post-retirement benefits including the anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation, benefit costs and annual pension funding requirements.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2020, are described as follows:

MEASUREMENT OF CREDIT LOSSES ON FINANCIAL INSTRUMENTS

The Company adopted Accounting Standard Update ("ASU") 2016-13, *Measurement of Credit Losses on Financial Instruments* effective January 1, 2020. 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. These include 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 adoption of the standard resulted in a $7 million decrease to retained earnings in the consolidated financial statements as of January 1, 2020.

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. It also 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 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2020, with early adoption permitted. The standard is applied on both a prospective and retrospective basis. The Company early adopted the standard effective January 1, 2020. There was no impact on the consolidated financial statements as a result of the adoption of this standard.

FACILITATION OF THE EFFECTS OF REFERENCE RATE REFORM ON FINANCIAL REPORTING

The Company adopted ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* in Q4 2020. The standard provides options and exceptions for applying USGAAP to contract modifications and hedging relationships that reference the London Inter-Bank Offered Rate ("LIBOR") or any other reference rate that is expected to be discontinued. The guidance was effective as of the date of issuance and entities may elect to apply the guidance prospectively through December 31, 2022. The Company's transition from reference rates will not have a material impact on the consolidated financial statements. In November 2020, the Federal Reserve extended the phase-out of LIBOR until June 2023. The Company will continue to monitor the impact this may have on application of the 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 as allowed, 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.

ACCOUNTING FOR CONVERTIBLE INSTRUMENTS AND CONTRACTS IN AN ENTITY'S OWN EQUITY

In August 2020, the FASB issued ASU 2020-06, Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40). The standard simplifies the accounting for convertible debenture debt instruments and convertible preferred stock, in addition to amending disclosure requirements. The standard also updates guidance for the derivative scope exception for contracts in an entity's own equity and the related earnings per share guidance. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2021. Early adoption is permitted, but no earlier than fiscal years beginning after December 15, 2020. The standard can be applied through either a modified retrospective method of transition or a fully retrospective method of transition. The Company early adopted the standard effective January 1, 2021 using the modified retrospective method. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

GUARANTEED DEBT SECURITIES DISCLOSURE REQUIREMENTS

In October 2020, the FASB issued ASU 2020-09, Debt (Topic 470): Amendments to SEC Paragraphs pursuant to SEC Release No. 33-10762. The change in the standard aligns with new SEC rules relating to changes to the disclosure requirements for certain registered debt securities that are guaranteed. The changes include simplifying disclosure, enhancing certain narrative disclosures and permitting the disclosures to be made outside of the financial statements. The guidance will be effective for annual reports filed for fiscal years ending after January 4, 2021, with early adoption permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

4. DISPOSITIONS

On March 24, 2020, Emera completed the sale of Emera Maine for a total enterprise value of approximately $2.0 billion including cash proceeds of $1.4 billion, transferred debt and working capital adjustments. A gain on disposition of $585 million ($309 million after tax) net of transaction costs, was recognized in the Other segment and included in "Other income" on the Consolidated Statements of Income.

Emera Maine's assets and liabilities were classified as held for sale at March 25, 2019. The Company continued recording depreciation on these assets through the transaction closing date, as the depreciation continued to be reflected in customer rates and was reflected in the carryover basis of the assets on completion of the sale. A total of $53 million of depreciation and amortization was recorded on these assets from March 25, 2019, the date they were classified as held for sale, until the date of the sale. $39 million of the $53 million was recorded in 2019. Emera Maine's assets and liabilities were included in the Company's Other Electric Utilities segment.

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. Emera's five 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, 2020							
Operating revenues from external customers (1)	**$ 2,473**	**$ 1,494**	**$ 474**	**$ 1,051**	**$ 14**	**$ –**	**$ 5,506**
Inter-segment revenues (1)	**7**	**–**	**–**	**7**	**15**	**(29)**	**–**
Total operating revenues	**2,480**	**1,494**	**474**	**1,058**	**29**	**(29)**	**5,506**
Regulated fuel for generation and purchased power	**574**	**659**	**194**	**–**	**–**	**(7)**	**1,420**
Regulated cost of natural gas	**–**	**–**	**–**	**293**	**–**	**–**	**293**
OM&G	**552**	**282**	**151**	**334**	**115**	**(15)**	**1,419**
Depreciation and amortization	**455**	**236**	**71**	**111**	**8**	**–**	**881**
Income from equity investments	**–**	**96**	**4**	**20**	**29**	**–**	**149**
AFUDC – debt and equity	**54**	**4**	**1**	**9**	**–**	**–**	**68**
Interest expense, net	**151**	**139**	**32**	**56**	**301**	**–**	**679**
Internally allocated interest (2)	**–**	**–**	**–**	**13**	**(13)**	**–**	**–**
Gain on sale, net of transactions costs	**–**	**–**	**–**	**–**	**585**	**–**	**585**
Impairment charges	**–**	**–**	**–**	**–**	**(25)**	**–**	**(25)**
Income tax expense (recovery)	**89**	**17**	**(8)**	**51**	**192**	**–**	**341**
Net income (loss) attributable to common shareholders	**501**	**221**	**35**	**162**	**19**	**–**	**938**
Capital expenditures	**1,361**	**338**	**148**	**749**	**4**	**–**	**2,600**
As at December 31, 2020							
Total assets	**16,889**	**6,752**	**1,365**	**6,067**	**1,234**	**(1,073)**(3)	**31,234**
Investments subject to significant influence	**–**	**1,176**	**41**	**129**	**–**	**–**	**1,346**
Goodwill	**4,455**	**–**	**68**	**1,194**	**3**	**–**	**5,720**

(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, 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
Regulated fuel for generation and purchased power	772	573	286	–	–	(22)	1,609
Regulated cost of natural gas	–	–	–	350	–	–	350
OM&G	554	313	195	319	130	(47)	1,464
Depreciation and amortization	445	231	107	109	11	–	903
Income from equity investments	–	91	5	22	36	–	154
AFUDC – debt and equity	20	6	5	2	–	–	33
Interest expense, net	154	142	52	59	331	–	738
Internally allocated interest (2)	–	–	–	14	(14)	–	–
Impairment charges	–	–	34	–	–	–	34
Income tax expense (recovery)	79	(10)	11	48	(67)	–	61
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.

GEOGRAPHICAL INFORMATION

Revenues (1):

For the millions of Canadian dollars	Year ended December 31 **2020**	2019
Canada	**$ 1,569**	$ 1,497
United States	**3,522**	4,140
Barbados	**263**	320
The Bahamas	**112**	112
Dominica	**40**	42
	$ 5,506	$ 6,111

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

Property Plant and Equipment:

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Canada	**$ 4,304**	$ 4,248
United States	**14,353**	13,095
Barbados	**510**	462
The Bahamas	**289**	282
Dominica	**79**	80
	$ 19,535	$ 18,167

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, 2020							
Regulated							
Electric Revenue							
Residential	$ 1,365	$ 806	$ 179	$ –	$ –	$ –	$ 2,350
Commercial	678	405	233	–	–	–	1,316
Industrial	178	224	32	–	–	–	434
Other electric and regulatory deferrals	242	31	8	–	–	–	281
Other (1)	17	28	22	1	–	(7)	61
Regulated electric revenue	2,480	1,494	474	1	–	(7)	4,442
Gas Revenue							
Residential	–	–	–	495	–	–	495
Commercial	–	–	–	275	–	–	275
Industrial	–	–	–	54	–	–	54
Finance income (2) (3)	–	–	–	61	–	–	61
Other	–	–	–	156	–	(7)	149
Regulated gas revenue	–	–	–	1,041	–	(7)	1,034
Non-Regulated							
Marketing and trading margin (4)	–	–	–	–	38	–	38
Energy sales (4)	–	–	–	–	16	(16)	–
Capacity	–	–	–	–	–	–	–
Other	–	–	–	16	21	–	37
Mark-to-market (3)	–	–	–	–	(46)	1	(45)
Non-regulated revenue	–	–	–	16	29	(15)	30
Total operating revenues	**$ 2,480**	**$ 1,494**	**$ 474**	**$ 1,058**	**$ 29**	**$ (29)**	**$ 5,506**

(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, 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.

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, 2020, the aggregate amount of the transaction price allocated to remaining performance obligations was $464 million (2019 – $347 million). This amount includes $149 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040. 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 2040.

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets represent prudently 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 millions of Canadian dollars	**December 31 2020**	December 31 2019
Regulatory assets		
Deferred income tax regulatory assets	**$ 887**	$ 862
Pension and post-retirement medical plan	**394**	380
Deferrals related to derivative instruments	**65**	81
Cost recovery clauses	**49**	13
Storm restoration regulatory asset	**41**	38
Environmental remediations	**28**	26
Stranded cost recovery	**26**	27
Demand side management ("DSM") deferral	**15**	19
Unamortized defeasance costs	**13**	19
Other	**66**	87
	$ 1,584	$ 1,552
Current	**$ 165**	$ 121
Long-term	**1,419**	1,431
Total regulatory assets	**$ 1,584**	$ 1,552
Regulatory liabilities		
Deferred income tax regulatory liabilities	**933**	985
Accumulated reserve – cost of removal	**865**	891
Storm reserve	**62**	62
Cost recovery clauses	**31**	53
Self-insurance fund (note 32)	**28**	29
Regulated fuel adjustment mechanism	**21**	115
Deferrals related to derivative instruments	**15**	42
Other	**6**	4
	$ 1,961	$ 2,181
Current	**$ 129**	$ 295
Long-term	**1,832**	1,886
Total regulatory liabilities	**$ 1,961**	$ 2,181

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 years, a regulatory asset or liability is recognized as appropriate.

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 and New Mexico Public Regulation Commission ("NMPRC") 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.

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 a subsequent period.

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, Hurricane 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.

In January 2020, the Grand Bahama Port Authority ("GBPA") approved the recovery of $15 million USD of costs related to the storm over a five-year period. The recovery was implemented through rates on January 1, 2021.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge over a five-year period. Additional details on the recovery are included under the Grand Bahama Power Company Limited section below. The balance of the regulatory asset as at December 31, 2020 is $18 million USD.

Environmental Remediations

This asset is primarily related to PGS costs associated with environmental remediation at Manufactured Gas Plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

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 and is expected to be included in rates in future years.

DSM Deferral

The Nova Scotia Utility and Review Board ("UARB") approved implementation of the 2015 DSM deferral set at $35 million in 2015 and recoverable from customers over an 8-year period beginning in 2016.

The UARB directed EfficiencyOne, a franchisee appointed by the Province of Nova Scotia to provide NSPI with electricity efficiency and conservation activities under the *Public Utilities Act*, 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. In February 2017, EfficiencyOne advanced an additional $2 million to NSPI. As NSPI collects the associated amounts from customers over the remaining three 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, 2020, totalled $582 million (2019 – $740 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 UARB.

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.

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.

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. 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. The UARB's decision to approve the Fuel Stability Plan directed that any annual non-fuel revenues above NSPI's approved range of ROE are to be applied to the FAM.

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 2020 and 2019 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.

Fuel Recovery

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.

Base Rates

On February 1, 2021, Tampa Electric notified the FPSC of its intent to seek a base rate increase, reflecting incremental revenue requirements of approximately $280 million USD to $295 million USD, effective January 2022. Tampa Electric's proposed rates include recovery for the costs of the first phase of the Big Bend modernization project, 225 MW of utility-scale solar projects, the AMI investment, and accelerated recovery of the remaining net book value of retiring assets. Tampa Electric also intends to seek approval for Generation Base Rate Adjustments of $130 million USD to recover the costs of the second phase of the Big Bend modernization project and additional utility-scale solar projects in subsequent years. These filing amounts are estimates until Tampa Electric completes and files its detailed case. Tampa Electric expects to file its detailed case on or after April 2, 2021, and a decision by the FPSC is expected by the end of 2021.

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.

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.

Solar Base Rate Adjustments Included in Base Rates

As of December 31, 2020, Tampa Electric has invested $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 600 MW or $104 million USD annually in estimated revenue requirements for in-service projects.

The true-up filing for SoBRAs tranche 1 and 2 revenue requirement estimates that were included in base rates as of September 2018 and January 2019, respectively, was submitted on April 30, 2020, and the FPSC approved the amount on August 18, 2020. A $5 million USD true-up was returned to customers in 2020. The true-ups for SoBRA tranches 3 and 4 will be filed in 2021 and 2022, respectively.

Storm Protection Cost Recovery Clause and Settlement Agreement

On October 3, 2019, the FPSC issued a rule to implement a Storm Protection Plan ("SPP") 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. Tampa Electric submitted its storm protection plan with the FPSC on April 10, 2020. On April 27, 2020, Tampa Electric submitted a settlement agreement with the FPSC which specified a $15 million USD base rate reduction for SPP program costs previously recovered in base rates beginning January 1, 2021. On June 9, 2020, the FPSC approved this settlement agreement. On August 3, 2020, Tampa Electric submitted another settlement agreement to the FPSC for approval, including cost recovery of approximately $39 million USD in proposed storm protection project costs for 2020 and 2021. This cost recovery includes the $15 million USD of costs removed from base rates. This settlement agreement was approved on August 10, 2020 and Tampa Electric's cost recovery began in January 2021. The current approved plan will apply for the years 2020, 2021 and 2022, and Tampa Electric will file a new plan in 2022 to determine cost recovery in 2023, 2024, and 2025.

The June 9, 2020 settlement agreement approved by the FPSC disclosed above also included approval of Tampa Electric's petition to eliminate its $16 million USD accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020.

Big Bend Modernization Project

Tampa Electric has invested approximately $526 million USD through December 31, 2020 to modernize the Big Bend Power Station. The modernization project will repower Big Bend Unit 1 with natural gas combined-cycle technology and eliminate coal as this unit's fuel. On June 1, 2020, Tampa Electric retired the Unit 1 components that will not be used in the modernized plant. At June 1, 2020 and December 31, 2020, the balance sheet included $304 million ($223 million USD) and $255 million ($200 million USD) respectively, in electric utility plant and $123 million ($90 million USD) and $112 million ($88 million USD) respectively, in accumulated depreciation related to Unit 1 components. In accordance with Tampa Electric's 2017 settlement agreement approved by the FPSC, Tampa Electric will continue to account for its existing investment in Unit 1 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study. In addition, Tampa Electric plans to retire Big Bend Unit 2 in 2021. In accordance with Tampa Electric's 2017 settlement agreement, Tampa Electric was not required to request an asset recovery schedule for retired assets until the next depreciation study. On December 30, 2020, Tampa Electric filed a depreciation and dismantlement study and request for capital recovery schedules with the FPSC.

Tampa Electric plans to retire Big Bend Unit 3 in 2023. Similar to the retirement plan for Unit 1 and Unit 2, Tampa Electric will continue to account for its existing investment in Unit 3 in electric utility plant and depreciate the assets using the current depreciation rates until the FPSC approves Tampa Electric's next depreciation and dismantlement study.

Canadian Electric Utilities

NSPI

NSPI is a public utility as defined in the *Public Utilities Act of Nova Scotia* ("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 a reasonable return to investors. NSPI's approved regulated ROE range for 2020 and 2019 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, approved by UARB which enables it to seek recovery of its fuel costs from customers through regularly scheduled fuel 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.

NSPI is currently operating under a 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.

The Maritime Link is a $1.6 billion transmission project including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018 and NSPI started paying the UARB approved interim assessment payments to NSPML at that time. The UARB approved 2020 interim cost assessment recovery payment to NSPML was $145 million and as of December 31, 2020 $135 million has been paid. The payments were 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. For 2020, NSPI has recorded a $4 million holdback payable to NSPML.

On December 16, 2020, the UARB approved NSPML's 2021 interim cost assessment recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million on similar terms as previously approved by the UARB. It also includes a potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the Nova Scotia Block ("NS Block"). Refer to the NSPML section below for further detail.

As part of a three-year fuel stability plan, electricity rates have been set to include the $145 million approved Maritime Link assessment for 2020 and estimate amounts of $164 million and $162 million for 2021 and 2022, respectively. Any difference between the amounts included in the Fuel Stability Plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

In response to the delayed timing of energy delivery from the Muskrat Falls project, which is being developed by Nalcor Energy, the approved Maritime Link interim assessment payments reflected a reduction in NSPML's assessment in each of 2018 and 2019, related to depreciation and amortization expenses. NSPI refunded the reduced 2018 NSPML assessment to customers in 2018 and 2019, by providing a credit to customers of $17 million and $35 million, respectively. The UARB's decision to approve NSPI's 2020-2022 fuel stability plan outlined the treatment of the reduced 2019 NSPML assessment of $52 million plus interest. The majority of the reduced assessment was refunded to most customers through a reduction incorporated into their 2020 rates and the remaining customers received a one-time on bill credit in 2020. As at December 31, 2020, $40 million plus interest has been refunded to customers, with the remaining $12 million plus interest to be returned to customers subsequent to 2022.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On August 21, 2020, the FAM audit results for 2018 and 2019 were filed with the UARB. A hearing was held in January 2021 and a decision is expected in Q2 2021.

On March 13, 2020, the UARB's decision on the FAM audit findings and recommendations relating to fiscal 2016 and 2017 was released. The final recommendations did not include any disallowances.

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 December 16, 2020 the UARB approved NSPML's 2021 interim assessment for recovery of Maritime Link costs from NSPI of approximately $172 million (2020 – $145 million). This payment is subject to a holdback of $10 million on similar terms as previously approved by the UARB. Recovery of $115 million of operating and maintenance, debt financing and equity financing costs began on January 1, 2021. Recovery of $57 million of depreciation and amortization will commence the sooner of the delivery of the NS Block or May 1, 2021. With cooperation of the Government of Canada, NSPML may also utilize up to $23 million of cash in a debt related reserve account to reduce the recovery of costs from NSPI in 2021, depending upon when the NS Block commences. NSPML will file a final cost assessment with the UARB after the commencement of the NS Block which is anticipated to take place in 2021.

Other Electric Utilities

The Barbados Light & Power Company Limited

BLPC is regulated by the Fair Trading Commission ("FTC"), 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 currently 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 2020 and 2019.

On November 6, 2020, BLPC notified the FTC that it plans to file a general rate review application with the FTC in Q1 2021.

BLPC has a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers 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 was 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, all of which was recognized in earnings in Q1 2020.

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 8.34 per cent for 2020 (2019 – 8.5 per cent). In January 2021, the GBPA approved GBPC's regulated return on rate base of 8.37 per cent for 2021.

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 2020 and 2019.

Domlec has a fuel pass-through mechanism which provides opportunity to recover substantially all prudently incurred 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.

PGS's approved ROE range for 2020 and 2019 was 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 was 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 beginning in 2013. In February 2017, the FPSC approved an amendment to the cast iron bare steel rider to include certain plastic materials and pipe deemed obsolete by Pipeline and Hazardous Materials Safety Administration, totaling approximately 880 kilometres. PGS estimates that all cast iron and bare steel pipe will be removed from its system by 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

PGS was permitted to initiate a general base rate proceeding during 2020, provided the new rates do not become effective before January 1, 2021. On June 8, 2020, PGS filed a petition for an increase in rates and service charges effective January 2021. On November 19, 2020, the FPSC approved a settlement agreement filed by PGS. The settlement agreement allows for an increase to base rates by $58 million USD annually effective January 2021, which is a $34 million USD increase in revenue and $24 million USD increase of revenues previously recovered through the cast iron and bare steel replacement rider. This settlement agreement includes an allowed regulatory ROE range of 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint. It provides PGS the ability to reverse a total of $34 million USD of accumulated depreciation through 2023 and sets new depreciation rates going into effect January 1, 2021 that are consistent with PGS's current overall average depreciation rate. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2023, unless its earned ROE were to fall below 8.9 per cent before that time with an allowed equity in the capital structure of 54.7 per cent from investor sources of capital. The settlement agreement provides for the deferral of income taxes as a result of changes in tax laws. The changes would be reflected as a regulatory asset or liability and either result in an increase or a decrease in customer rates through a subsequent regulatory process.

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.

NMGC's approved ROE for 2020 was 9.10 per cent and for 2019 ranged from 9.10-10.0 per cent. Beginning January 1, 2021, the approved ROE is 9.375 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 2020, NMGC received approval of its PGAC Continuation Filing for the four-year period ending December 2024.

NMGC filed a rate case in December 2019. NMGC reached an unopposed stipulated settlement of the case which was approved by the NMPRC in December 2020. The new rates reflect the recovery of capital investment in pipelines and related infrastructure and results in an increase in revenue of approximately $5 million USD annually effective January 2021.The stipulated settlement agreement includes an allowed regulatory ROE 9.375 per cent on an allowed equity capital structure of 52 per cent. Under the agreement base rates are frozen from January 1, 2021 to December 31, 2022, unless new federal tax rates are enacted, in which case NMGC can file for new rates to be effective earlier than January 1, 2023.

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 were phased in over two years, resulting 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. This clause is designed to lower the variability of weather impacts during the heating season period of October through April annually. The Weather Normalization Mechanism will make customer rates and Company revenue more predictable by minimizing the impact of warmer than usual or colder than usual weather. Revenue increases or decreases captured in the weather normalization mechanism from October to April will be adjusted annually in October of the following heating season.

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.

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 agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract. The pipeline is considered a Group II pipeline regulated by the Canada Energy Regulator ("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.

8. 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
	2020	2019	**2020**	2019	**2020**
LIL (1)	**$ 629**	$ 579	**$ 49**	$ 45	**45.6**
NSPML	**547**	554	**47**	46	**100.0**
M&NP (2)	**129**	138	**20**	22	**12.9**
Lucelec (2)	**41**	41	**4**	3	**19.5**
Bear Swamp (3)	**–**	–	**29**	35	**50.0**
Other Investments	**–**	–	**–**	3	
	$ 1,346	$ 1,312	**$ 149**	$ 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 as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $118 million (2019 – $137 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a $12 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Balance Sheets		
Current assets	**$ 57**	$ 69
Property, plant and equipment	**1,629**	1,671
Regulatory assets	**210**	177
Non-current assets	**32**	32
Total assets	**$ 1,928**	$ 1,949
Current liabilities	**$ 56**	$ 23
Long-term debt (1)	**1,228**	1,288
Non-current liabilities	**97**	84
Equity	**547**	554
Total liabilities and equity	**$ 1,928**	$ 1,949

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

9. OTHER INCOME (EXPENSES), NET

Other income (expenses), net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2020**	 2019
Allowance for equity funds used during construction	**$ 45**	$ 21
Gain on sale of Emera Maine, net of transaction costs (1)	**585**	–
TECO Guatemala Holdings award (2)	**49**	–
Other	**29**	(9)
	$ 708	$ 12

(1) Refer to note 4 for further detail related to the gain on sale of Emera Maine.
(2) Refer to note 27 for further detail related to the TECO Guatemala Holdings award.

10. INCOME TAXES

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

millions of Canadian dollars	**2020**	2019
Income before provision for income taxes	**$ 1,325**	$ 771
Statutory income tax rate	**29.5%**	31%
Income taxes, at statutory income tax rate	**391**	239
Additional impact from the sale of Emera Maine	**102**	–
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(48)**	(66)
Foreign tax rate variance	**(45)**	(49)
Amortization of deferred income tax regulatory liabilities	**(44)**	(36)
Tax effect of equity earnings	**(15)**	(15)
Other	**–**	(12)
Income tax expense	**$ 341**	$ 61
Effective income tax rate	**26%**	8%

The increase in the effective income tax rate was primarily due to the sale of Emera Maine.

On March 10, 2020, Bill 243 of the Nova Scotia Financial Measures (2020) Act ("the Financial Measures Act") was enacted, which included a reduction in the Nova Scotia provincial corporate income tax rate from 16 per cent to 14 per cent. As a result, the Company's combined Canadian federal and provincial statutory income tax rate was reduced from 31 per cent to 29.5 per cent for 2020 and further reduced to 29 per cent for subsequent years.

As a result of this, the Company, in Q1 2020, was required to revalue certain of its Canadian deferred income tax assets and liabilities based on the new tax rates. The Company recorded a reduction of $52 million to its net deferred income tax liabilities and an offsetting reduction to its net deferred income tax regulatory asset, as the benefit of lower net deferred income tax liabilities is expected to be returned to customers in future years. The Company also recognized a $12 million income tax expense in Q1 2020 as a result of the revaluation of certain net deferred income tax assets.

On March 25, 2020, Bill C-13, the Canadian COVID-19 Emergency Response Act ("the COVID-19 Act") was enacted, guaranteeing rapid implementation and administration of measures to protect Canadians' health and safety, and stabilize the economy. In addition, the Government of Canada announced the opportunity for businesses to defer certain tax payments. There have been no material impacts to Emera's financial position from the COVID-19 Act or the Government of Canada's announcements.

On March 27, 2020, the United States Coronavirus Aid, Relief, and Economic Security (CARES) Act ("the CARES Act") was signed into law. The CARES Act includes several business provisions including deferral of employer payroll taxes, an employee retention payroll tax credit, temporary changes to business interest expense disallowance rules, changes to net operating loss carryback and limitation rules and corporate alternative minimum tax ("AMT") relief. Under the new AMT provisions, companies can accelerate the refund of AMT credit carryforwards. As a result, in Q1 2020, the Company reclassified $77 million of AMT credit carryforwards from deferred income tax assets to receivables and other current assets. The Company received $145 million of refundable AMT credit carryforwards in Q4 2020. The Company has not had any other material impacts from the CARES Act.

The following table 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	**2020**	2019
Current income taxes		
Canada	**$ 18**	$ (19)
United States	**(58)**	(46)
Other	**–**	1
Deferred income taxes		
Canada	**20**	45
United States	**426**	137
Other	**(9)**	–
Investment tax credits		
United States	**(10)**	(9)
Operating loss carryforwards		
Canada	**(46)**	(48)
Income tax expense	**$ 341**	$ 61

The following table 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	**2020**	2019
Canada	**$ 176**	$ 98
United States	**1,142**	682
Other	**7**	(9)
Income before provision for income taxes	**$ 1,325**	$ 771

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	2020	2019
Deferred income tax assets:		
Tax loss carryforwards	**$ 724**	$ 908
Tax credit carryforwards	**319**	311
Regulatory liabilities – cost of removal	**184**	195
Derivative instruments	**108**	145
Other	**375**	413
Total deferred income tax assets before valuation allowance	**1,710**	1,972
Valuation allowance	**(202)**	(193)
Total deferred income tax assets after valuation allowance	**$ 1,508**	$ 1,779
Deferred income tax (liabilities):		
Property, plant and equipment	**$ (2,450)**	$ (2,382)
Derivative instruments	**(93)**	(148)
Other	**(385)**	(348)
Total deferred income tax liabilities	**(2,928)**	(2,878)
Consolidated Balance Sheets presentation:		
Long-term deferred income tax assets	**$ 209**	$ 186
Long-term deferred income tax liabilities	**(1,629)**	(1,285)
Net deferred income tax liabilities	**$ (1,420)**	$ (1,099)

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 $202 million has been recorded as at December 31, 2020 (2019 – $193 million) related to the loss carryforwards and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, $2.7 billion as at December 31, 2020 (2019 – $1.9 billion) in cumulative temporary differences for which deferred taxes might otherwise be required, have not been recognized. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera's net operating loss ("NOL"), capital loss and tax credit carryforwards and their expiration periods as at December 31, 2020 consisted of the following:

millions of Canadian dollars	Gross Tax Carryforwards	Unrecognized Amounts	Net Tax Carryforwards	Expiration Period
Canada				
NOL	$ 1,370	$ (619)	$ 751	2027-2040
Capital loss	61	(61)	–	Indefinite
United States				
Federal NOL	$ 1,412	$ –	$ 1,412	2030-2040
State NOL	563	–	563	2032-2040
Tax credit	319	–	319	2025-2040
Other				
NOL	$ 39	$ (39)	$ –	2021-2027

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

millions of Canadian dollars	2020	2019
Balance, January 1	**$ 29**	$ 26
Increases due to tax positions related to current year	**1**	2
Increases due to tax positions related to a prior year	**2**	1
Decreases due to tax positions related to a prior year	**(2)**	–
Balance, December 31	**$ 30**	$ 29

The total amount of unrecognized tax benefits as at December 31, 2020 was $30 million (2019 – $29 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $6 million (2019 – $5 million) with $1 million of interest expense recognized in the Consolidated Statements of Income (2019 – $1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next 12 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.

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 that 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.

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, 2020, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

11. COMMON STOCK

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

		2020		2019
Issued and outstanding:	**millions of shares**	**millions of Canadian dollars**	millions of shares	millions of Canadian dollars
Balance, December 31, 2019	**242.48**	**$ 6,216**	234.12	$ 5,816
Conversion of Convertible Debentures	**–**	**–**	0.03	1
Issuance of common stock (1) (2)	**4.54**	**251**	1.77	99
Issued under Purchase Plans at market rate	**3.99**	**219**	3.99	202
Discount on shares purchased under Dividend Reinvestment Plan	**–**	**(4)**	–	(7)
Options exercised under senior management share option plan	**0.42**	**20**	2.57	104
Employee Share Purchase Plan	**–**	**3**	–	1
Balance, December 31, 2020	**251.43**	**$ 6,705**	242.48	$ 6,216

(1) As at December 31, 2019, a total of 1,768,120 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.56 per share for gross proceeds of $100 million ($99 million net of issuance costs).

(2) For the year ended December 31, 2020, 4,544,025 common shares were issued under Emera's ATM program at an average price of $56.04 per share for gross proceeds of $255 million ($251 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, 2020, an aggregate gross sales limit of $245 million remains available for issuance under the ATM program.

On November 17, 2020, Emera filed an amendment to its July 11, 2019 prospectus supplement which established its ATM program. This amendment reflected changes in securities regulations related to ATM programs which were effective August 31, 2020. The amendment includes removal of the daily trading limit which previously provided that the number of shares sold could not exceed 25 per cent of the daily trading volume of the shares.

As at December 31, 2020, the following common shares were reserved for issuance: 3.5 million (2019 – 3.9 million) under the senior management stock option plan, 3.5 million (2019 – 0.9 million) under the employee common share purchase plan and 5.1 million (2019 – 8.8 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, 2020, Emera is in compliance with this requirement.

12. 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)	**2020**	2019
Numerator		
Net income attributable to common shareholders	**$ 937.6**	$ 662.8
Diluted numerator	**937.6**	662.8
Denominator		
Weighted average shares of common stock outstanding	**246.5**	238.5
Weighted average deferred share units outstanding	**1.3**	1.4
Weighted average shares of common stock outstanding – basic	**247.8**	239.9
Stock-based compensation	**0.4**	0.6
Weighted average shares of common stock outstanding – diluted	**248.2**	240.5
Earnings per common share		
Basic	**$ 3.78**	$ 2.76
Diluted	**$ 3.78**	$ 2.76

13. 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, 2020						
Balance, January 1, 2020	**$ 253**	**$ 4**	**$ (1)**	**$ (1)**	**$ (160)**	**$ 95**
Other comprehensive income (loss) before reclassifications	**(201)**	**26**	**–**	**–**	**–**	**(175)**
Amounts reclassified from accumulated other comprehensive income loss (gain)	**–**	**–**	**2**	**–**	**(1)**	**1**
Net current period other comprehensive income (loss)	**(201)**	**26**	**2**	**–**	**(1)**	**(174)**
Balance, December 31, 2020	**$ 52**	**$ 30**	**$ 1**	**$ (1)**	**$ (161)**	**$ (79)**
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	–	–	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

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

For the		Year ended December 31	
millions of Canadian dollars		**2020**	2019
	Affected line item in the Consolidated Financial Statements		
Losses on derivatives recognized as cash flow hedges			
Foreign exchange forwards	Operating revenue – regulated	**$ 2**	$ 3
Total before tax		**2**	3
Total net of tax		**$ 2**	$ 3
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	Other income, net	**$ 15**	$ 17
Past service costs (gains)	Other income, net	**(1)**	(1)
Amounts reclassified into obligations	Pension and post-retirement benefits	**(16)**	39
Amounts reclassified into obligations	Regulatory assets	**–**	28
Total before tax		**(2)**	83
	Income tax recovery (expense)	**1**	(9)
Total net of tax		**$ (1)**	$ 74
Total reclassifications out of AOCI, net of tax, for the period		**$ 1**	$ 77

14. INVENTORY

As at millions of Canadian dollars	December 31 2020	December 31 2019
Fuel	$ 199	$ 232
Materials	254	235
	$ 453	$ 467

15. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	December 31 2020	December 31 2019	December 31 2020	December 31 2019
Cash flow hedges				
Interest rate hedge	$ 1	$ –	$ –	$ –
Foreign exchange forwards	–	–	–	1
	1	–	–	1
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	1	8	6	39
Power purchases	10	23	34	36
Natural gas purchases and sales	4	2	2	5
Heavy fuel oil purchases	1	1	5	–
Foreign exchange forwards	–	2	17	6
	16	36	64	86
HFT derivatives				
Power swaps and physical contracts	13	19	13	22
Natural gas swaps, futures, forwards, physical contracts	139	151	346	381
	152	170	359	403
Other derivatives				
Equity derivatives	–	1	1	–
Foreign exchange forwards	15	–	–	–
	15	1	1	–
Total gross current derivatives	184	207	424	490
Impact of master netting agreements with intent to settle net or simultaneously	(86)	(120)	(86)	(120)
	98	87	338	370
Current	73	54	251	268
Long-term	25	33	87	102
Total derivatives	$ 98	$ 87	$ 338	$ 370

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Details of master netting agreements, shown net on the Consolidated Balance Sheets, are summarized in the following table:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	December 31 2020	December 31 2019	December 31 2020	December 31 2019
Regulatory deferral	$ 2	$ 8	$ 2	$ 8
HFT derivatives	84	112	84	112
Total impact of master netting agreements with intent to settle net or simultaneously	$ 86	$ 120	$ 86	$ 120

CASH FLOW HEDGES

As at December 31, 2020 the Company had a treasury lock in place to hedge the interest rate risk associated with the refinancing of long-term debt due in June 2021. During 2020 the Company also had foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline. The foreign exchange forwards designated as cash flow hedges settled in 2020.

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	**2020**		2019
	Foreign exchange forwards	**Interest rate hedge**	Foreign exchange forwards
Realized gain (loss) in operating revenue – regulated	**$ (2)**	**$ –**	$ (3)
Total gains (losses) in net income	**$ (2)**	**$ –**	$ (3)

As at	December 31		
millions of Canadian dollars	**2020**		2019
	Foreign exchange forwards	**Interest rate hedge**	Foreign exchange forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ –**	**$ 1**	$ (1)

The Company expects $1 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months, as the underlying hedged transactions settle.

As at December 31, 2020, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2021
U.S. Treasury lock (USD)	$ 350

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	**2020**		2019	
	Commodity swaps and forwards	**Foreign exchange forwards**	Commodity swaps and forwards	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (36)**	**$ (11)**	$ (89)	$ (6)
Unrealized gain (loss) in regulatory liabilities	**3**	**3**	9	(8)
Realized gain (loss) in regulatory assets	**2**	**–**	–	–
Realized (gain) loss in regulatory liabilities	**14**	**–**	(2)	–
Realized (gain) loss in inventory (1)	**8**	**(2)**	(36)	(11)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**24**	**(3)**	3	(8)
Total change derivative instruments	**$ 15**	**$ (13)**	$ (115)	$ (33)

(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 and hedging relationships that have been terminated or the hedged transaction is no longer probable.

COMMODITY SWAPS AND FORWARDS

As at December 31, 2020, 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	2021	2022–2023
	Purchases	Purchases
Natural Gas (Mmbtu)	5	7
Power (MWh)	2	2
Heavy fuel oil (bbls)	–	1
Coal (metric tonnes)	–	1

FOREIGN EXCHANGE SWAPS AND FORWARDS

As at December 31, 2020, 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:

	2021	2022–2023
Foreign exchange contracts (millions of US dollars)	$ 160	$ 135
Weighted average rate	1.3339	1.3266
% of USD requirements	78%	37%

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	Year ended December 31	
millions of Canadian dollars	**2020**	2019
Power swaps and physical contracts in non-regulated operating revenues	**$ (1)**	$ 1
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**205**	281
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(4)**	(6)
	$ 200	$ 276

As at December 31, 2020, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2021	2022	2023	2024	2025
Natural gas purchases (Mmbtu)	387	61	45	26	26
Natural gas sales (Mmbtu)	412	50	17	2	2
Power purchases (MWh)	2	–	–	–	–
Power sales (MWh)	1	–	–	–	–

OTHER DERIVATIVES

As at December 31, 2020, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and foreign exchange forwards in place to manage cash flow risk associated with forecasted US dollar cash inflows. The equity derivative hedges the return on 2.8 million shares and extends until December of 2021. The foreign exchange forwards have a combined notional amount of $100 million USD and expire in 2021.

For the millions of Canadian dollars	**2020** **Foreign Exchange Forwards**	**2020** **Equity Derivatives**	Year ended December 31 2019 Foreign Exchange Forwards	2019 Equity Derivatives
Unrealized gain (loss) in operating, maintenance and general	**$ –**	**$ (1)**	$ –	$ 1
Unrealized gain (loss) in other income (expense), net	**15**	**–**	–	–
Realized gain (loss) in operating, maintenance and general	**–**	**(3)**	–	27
Realized gain (loss) in other income (expense)	**(2)**	**–**	–	–
Total gains (losses) in net income	**$ 13**	**$ (4)**	$ –	$ 28

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, 2020, the maximum exposure the Company has to credit risk is $805 million (2019 – $860 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, 2020 was $251 million (2019 – $259 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, 2020, the Company had $123 million (2019 – $115 million) in financial assets, considered to be past due, which have been outstanding for an average 70 days. The fair value of these financial assets is $101 million (2019 – $106 million), the difference of which is included in the allowance for credit losses. 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, 2020		December 31, 2019	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**$ 341**	**32%**	$ 344	31%
Commercial	**143**	**14%**	170	15%
Industrial	**49**	**5%**	66	6%
Other	**96**	**9%**	131	12%
	629	**60%**	711	64%
Trading group				
Credit rating of A- or above	**54**	**5%**	38	3%
Credit rating of BBB- to BBB+	**41**	**4%**	59	5%
Not rated	**75**	**7%**	95	9%
	170	**16%**	192	17%
Other accounts receivable	**159**	**15%**	184	16%
Classification as assets held for sale (1)	**-**	**0%**	(55)	-5%
	958	**91%**	1,032	92%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**60**	**6%**	47	4%
Credit rating of BBB- to BBB+	**13**	**1%**	8	1%
Not rated	**25**	**2%**	32	3%
	98	**9%**	87	8%
	$ 1,056	**100%**	$ 1,119	100%

(1) Emera Maine's assets and liabilities were classified as held for sale at December 31, 2019. On March 24, 2020, Emera completed the sale of Emera Maine. Refer to note 4 for further detail.

CASH COLLATERAL

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

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Cash collateral provided to others	**$ 69**	$ 101
Cash collateral received from others	**6**	2

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, 2020, the total fair value of derivatives in a liability position, was $338 million (December 31, 2019 – $370 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 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, 2020
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Interest rate hedge	$ 1	$ –	$ –	$ 1
	1	–	–	1
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	9	–	–	9
Natural gas purchases and sales	2	1	–	3
Heavy fuel oil purchases	–	2	–	2
	11	3	–	14
HFT derivatives				
Power swaps and physical contracts	3	2	2	7
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	48	12	61
	4	50	14	68
Other derivatives				
Foreign exchange forwards	–	15	–	15
	–	15	–	15
Total assets	16	68	14	98
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	–	4	–	4
Power purchases	33	–	–	33
Heavy fuel oil purchases	3	3	–	6
Natural gas purchases and sales	–	2	–	2
Foreign exchange forwards	–	17	–	17
	36	26	–	62
HFT derivatives				
Power swaps and physical contracts	4	2	1	7
Natural gas swaps, futures, forwards and physical contracts	1	10	257	268
	5	12	258	275
Other derivatives				
Equity derivatives	1	–	–	1
	1	–	–	1
Total liabilities	42	38	258	338
Net assets (liabilities)	$ (26)	$ 30	$ (244)	$ (240)

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)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2020 was as follows:

			HFT Derivatives
millions of Canadian dollars	**Power**	**Natural gas**	**Total**
Balance, January 1, 2020	**$ 1**	**$ 14**	**$ 15**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**3**	**(2)**	**1**
Net transfers out of Level 3	**(2)**	**–**	**(2)**
Balance, December 31, 2020	**$ 2**	**$ 12**	**$ 14**

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2020 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, January 1, 2020	$ –	$ 249	$ 249
Total realized and unrealized gains included in non-regulated operating revenues	2	8	10
Net transfers out of Level 3	(1)	–	(1)
Balance, December 31, 2020	$ 1	$ 257	$ 258

The Company evaluates observable inputs of market data on a quarterly basis to determine if transfers between levels is appropriate. For the year ended December 31, 2020, transfers out of Level 3 were a result of an increase in observable inputs.

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. 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, 2020
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted Average (1)
Assets					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	**$20.50 – $62.45**	**$31.14**
			Probability of default	**0.02% – 9.74%**	**2.52%**
			Discount rate	**0.01% – 0.73%**	**0.25%**
	1	Modelled pricing	Third-party pricing	**$25.70 – $36.05**	**$29.53**
			Probability of default	**0.36% – 0.85%**	**0.60%**
			Discount rate	**0.06% – 0.41%**	**0.28%**
			Correlation factor	**100% – 100%**	**100%**
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts	18	Modelled pricing	Third-party pricing	**$1.66 – $6.22**	**$2.52**
			Probability of default	**0.02% – 2.52%**	**0.40%**
			Discount rate	**0.00% – 10.36%**	**0.75%**
	(6)	Modelled pricing	Third-party pricing	**$1.82 – $8.44**	**$4.66**
			Basis adjustment	**$0.00 – $1.33**	**$0.44**
			Probability of default	**0.02% – 12.58%**	**$1.95**
			Discount rate	**0.00% – 0.67%**	**0.13%**
Total assets	**$ 14**				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	**$1.13 – $62.45**	**$36.90**
			Own credit risk	**0.02% – 6.85%**	**2.02%**
			Discount rate	**0.01% – 0.73%**	**0.34%**
	1	Modelled pricing	Third-party pricing	**$37.25 – $62.45**	**$55.00**
			Own credit risk	**0.36% – 1.28%**	**0.83%**
			Discount rate	**0.01% – 0.40%**	**0.31%**
			Correlation factor	**100% – 100%**	**100%**
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts	226	Modelled pricing	Third-party pricing	**$1.44 – $6.57**	**$3.68**
			Own credit risk	**0.02% – 2.52%**	**0.10%**
			Discount rate	**0.00% – 8.79%**	**0.43%**
	30	Modelled pricing	Third-party pricing	**$1.54 – $8.44**	**$4.69**
			Basis adjustment	**$0.00 – $1.33**	**$0.87**
			Own credit risk	**0.03% – 12.58%**	**0.10%**
			Discount rate	**0.00% – 0.67%**	**0.16%**
Total liabilities	**$ 258**				
Net assets (liabilities)	**$ (244)**				

(1) Unobservable inputs were weighted by the relative fair value of the instruments.

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)				

Long-term debt is a financial liability not measured at fair value on the Consolidated Balance Sheets. The balance consisted of the following:

As at millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2020	**$ 13,721**	**$ 16,487**	**$ –**	**$ 16,020**	**$ 467**	**$ 16,487**
December 31, 2019	$ 14,180	$ 16,049	$ –	$ 15,598	$ 451	$ 16,049

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 $26 million was recorded in Other Comprehensive Income for the year ended December 31, 2020 (2019 – $78 million).

17. 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 $139 million for the year ended December 31, 2020 (2019 – $107 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 $18 million for the year ended December 31, 2020 (2019 – $63 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, 2020 and at December 31, 2019.

18. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Customer accounts receivable – billed	**$ 570**	$ 603
Customer accounts receivable – unbilled	**286**	265
Allowance for credit losses	**(22)**	(9)
Capitalized transportation capacity (1)	**200**	272
Income tax receivable	**11**	118
Prepaid expenses	**50**	48
Other	**138**	189
	$ 1,233	$ 1,486

(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.

19. 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 65 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 millions of Canadian dollars	Classification	**December 31 2020**	December 31 2019
Right-of-use asset	Other long-term assets	**$ 61**	$ 64
Lease liabilities			
Current	Other current liabilities	**3**	5
Long-term	Other long-term liabilities	**60**	61
Total lease liabilities		**$ 63**	$ 66

The Company has recorded lease expense of $160 million for the year ended December 31, 2020 (2019 – $172 million), of which $149 million (2019 – $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	2021	2022	2023	2024	2025	Thereafter	Total
Minimum lease payments	$ 6	$ 6	$ 6	$ 5	$ 4	$ 112	$ 139
Less imputed interest	–	–	–	–	–	–	(76)
Total	$ 6	$ 6	$ 6	$ 5	$ 4	$ 112	$ 63

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

For the	**Year ended December 31 2020**	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of Canadian dollars)	**$ 7**	$ 7
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of Canadian dollars)	**$ 7**	$ 16
Weighted average remaining lease term (years)	**43**	39
Weighted average discount rate – operating leases	**3.96%**	4.07%

LESSOR

The Company's net investment in direct finance and sales-type leases primarily relates 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:

As at millions of Canadian dollars	December 31 2020	December 31 2019
Total minimum lease payment to be received	**$ 1,018**	$ 1,066
Less: amounts representing estimated executory costs	**(179)**	(189)
Minimum lease payments receivable	**$ 839**	$ 877
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: unearned finance lease income	**(487)**	(532)
Net investment in direct finance and sales-type leases	**$ 535**	$ 528
Principal due within one year (included in "Receivables and other current assets")	**18**	17
Net investment in sales-type leases – long-term (included in "Other long-term assets")	**42**	38
Net Investment in direct finance leases – long-term	**$ 475**	$ 473

As at December 31, 2020, 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	2021	2022	2023	2024	2025	Thereafter	Total
Minimum lease payments to be received	$ 78	$ 77	$ 76	$ 77	$ 79	$ 631	$ 1,018
Less: executory costs							(179)
Minimum lease payments receivable	$ 78	$ 77	$ 76	$ 77	$ 79	$ 631	$ 839

20. PROPERTY, PLANT AND EQUIPMENT

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

As at millions of Canadian dollars	Estimated useful life	December 31 2020	December 31 2019
Generation	3 to 131	**$ 11,474**	$ 11,181
Transmission	11 to 80	**2,414**	2,318
Distribution	4 to 80	**5,997**	5,820
Gas transmission and distribution	7 to 85	**3,879**	3,568
General plant and other (1)	2 to 60	**2,127**	2,006
Total cost		**25,891**	24,893
Less: Accumulated depreciation (1)		**(8,714)**	(8,317)
		17,177	16,576
Construction work in progress (1)		**2,358**	1,591
Net book value		**$ 19,535**	$ 18,167

(1) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2020, SeaCoast's share of plant in service was $34 million, accumulated depreciation of nil and construction work in progress of nil. At December 31, 2019, SeaCoast's share of construction work in progress was $8 million. SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest was a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in OM&G in the Consolidated Statements of Income.

21. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, New Mexico, Barbados, Dominica and Grand Bahama Island. On March 24, 2020, Emera sold Emera Maine, refer to note 4 for further detail. As at December 31, 2019, Emera Maine's assets and liabilities, including balances related to benefit plans, were classified as held for sale.

Emera's net periodic benefit cost included the following:

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	**2020**		2019	
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	**$ 2,822**	**$ 353**	$ 2,650	$ 350
Service cost	**46**	**5**	47	4
Plan participant contributions	**7**	**5**	8	5
Interest cost	**84**	**10**	102	14
Benefits paid	**(135)**	**(27)**	(130)	(23)
Actuarial losses	**189**	**52**	231	19
Settlements and curtailments	**(229)**	**(52)**	(20)	–
Foreign currency translation adjustment	**(25)**	**(7)**	(66)	(16)
Balance, December 31	**2,759**	**339**	2,822	353
Change in plan assets				
Balance, January 1	**2,593**	**56**	2,300	49
Employer contributions	**41**	**21**	52	19
Plan participant contributions	**7**	**5**	8	5
Benefits paid	**(135)**	**(27)**	(130)	(23)
Actual return on assets, net of expenses	**310**	**5**	424	7
Settlements and curtailments	**(191)**	**(7)**	(7)	–
Foreign currency translation adjustment	**(20)**	**(1)**	(54)	(1)
Balance, December 31	**2,605**	**52**	2,593	56
Funded status, end of year	**$ (154)**	**$ (287)**	$ (229)	$ (297)

The actuarial losses recognized in the period are primarily due to losses associated with changes in the discount rate and losses related to changes in member experience, such as terminations, retirements, and deaths. This was partially offset by gains associated with strong asset performance and changes in inflation and compensation-related assumptions.

PLANS WITH PBO/APBO IN EXCESS OF PLAN ASSETS

The aggregate financial position for all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeds the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	**2020**		2019	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 2,736**	**$ 308**	$ 2,797	$ 323
Fair value of plan assets	**2,568**	**–**	2,557	7
Funded status	**$ (168)**	**$ (308)**	$ (240)	$ (316)

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

The ABO for the defined benefit pension plans was $2,639 million as at December 31, 2020 (2019 – $2,687 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	**2020**	2019
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 1,519**	$ 2,665
Fair value of plan assets	**1,419**	2,557
Funded status	**$ (100)**	$ (108)

BALANCE SHEET

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

As at millions of Canadian dollars		**December 31 2020**		December 31 2019
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Other current liabilities	**$ (4)**	**$ (19)**	$ (4)	$ (18)
Long-term liabilities	**(163)**	**(290)**	(206)	(254)
Long-term liabilities associated with assets held for sale (1)	**–**	**–**	(30)	(44)
Other long-term assets	**13**	**20**	11	19
Amount included in deferred income tax	**(4)**	**(1)**	(7)	1
AOCI and regulatory assets, net of tax	**443**	**107**	524	72
Net amount recognized	**$ 285**	**$ (183)**	$ 288	$ (224)

(1) On March 24, 2020, Emera sold Emera Maine, refer to note 4 for further details. As at December 31, 2019, Emera Maine's assets and liabilities were classified as held for sale.

AMOUNTS RECOGNIZED IN AOCI AND REGULATORY ASSETS

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial (gains) losses	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2020	$ 358	$ 160	$ (1)
Amortized in current period	(25)	(15)	1
Current year addition to AOCI or regulatory assets	(12)	14	–
Change in current year related to sale of Emera Maine	(39)	–	–
Change in foreign exchange rate	(3)	1	–
Balance, December 31, 2020	$ 279	$ 160	$ –
Non-pension benefits plans			
Balance, January 1, 2020	$ 78	$ (5)	$ –
Amortized in current period	–	–	–
Current year addition to AOCI or regulatory assets	48	2	–
Change in current year related to sale of Emera Maine	(13)	–	–
Change in foreign exchange rate	(3)	(1)	–
Balance, December 31, 2020	$ 110	$ (4)	$ –

	2020		2019	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses (gains)	**$ 160**	**$ (4)**	$ 160	$ (5)
Past service (gains) costs	**–**	**–**	(1)	–
Regulatory assets	**279**	**110**	358	78
Total AOCI and regulatory assets before deferred income taxes	**439**	**106**	517	73
Amount included in deferred income tax assets	**4**	**1**	7	(1)
Net amount in AOCI and regulatory assets	**$ 443**	**$ 107**	$ 524	$ 72

BENEFIT COST COMPONENTS

Emera's net periodic benefit cost included the following:

As at			Year ended December 31	
millions of Canadian dollars	2020		2019	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 46**	**$ 5**	$ 47	$ 4
Interest cost	**84**	**10**	102	14
Expected return on plan assets	**(141)**	**(1)**	(147)	(2)
Current year amortization of:				
Actuarial losses (gains)	**15**	**–**	16	–
Past service costs (gains)	**(1)**	**–**	(1)	–
Regulatory assets (liability)	**25**	**–**	20	(5)
Settlement, curtailments	**–**	**–**	1	–
Total	**$ 28**	**$ 14**	$ 38	$ 11

The expected return on plan assets is determined based on the market-related value of plan assets of $2,476 million as at January 1, 2020 (2019 – $2,401 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 range 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	30% to 50%
Equities	50% to 70%

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, 2020**
	NAV	**Level 1**	**Level 2**	**Total**	**Percentage**
Cash and cash equivalents	**$ –**	**$ 68**	**$ –**	**$ 68**	**3%**
Net in-transits	**–**	**(99)**	**–**	**(99)**	**(4)%**
Equity securities:					
Canadian equity	**–**	**154**	**–**	**154**	**6%**
US equity	**–**	**380**	**–**	**380**	**15%**
Other equity	**–**	**243**	**–**	**243**	**9%**
Fixed income securities:					
Government	**–**	**–**	**119**	**119**	**5%**
Corporate	**–**	**–**	**141**	**141**	**5%**
Other	**–**	**10**	**3**	**13**	**–%**
Mutual funds	**–**	**88**	**–**	**88**	**3%**
Other	**–**	**(3)**	**(4)**	**(7)**	**–%**
Open-ended investments measured at NAV (1)	**801**	**–**	**–**	**801**	**31%**
Common collective trusts measured at NAV (2)	**704**	**–**	**–**	**704**	**27%**
Total	**$ 1,505**	**$ 841**	**$ 259**	**$ 2,605**	**100%**

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%

(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 16 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 is the NMGC Retiree Medical Plan, which is fully funded. Prior to its sale on March 24, 2020, the Emera Maine post-retirement benefit plans were partially funded.

INVESTMENTS IN EMERA

As at December 31, 2020 and 2019, the assets related to the pension funds and post-retirement benefit plans do not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

CASH FLOWS

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2021	$ 41	$ 19
Expected benefit payments		
2021	140	21
2022	154	22
2023	154	22
2024	162	22
2025	170	22
2026–2030	914	105

ASSUMPTIONS

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

	2020		2019	
(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	**2.49%**	**2.48%**	3.17%	3.27%
Discount rate – future service	**2.64%**	**2.51%**	3.21%	3.28%
Rate of compensation increase	**2.89%**	**3.04%**	3.32%	3.70%
Health care trend – initial (next year)	**–**	**5.64%**	–	6.15%
– ultimate	**–**	**4.35%**	–	4.38%
– year ultimate reached		**2038**		2038
Benefit cost for year ended December 31:				
Discount rate – past service	**3.17%**	**3.28%**	4.05%	4.30%
Discount rate – future service	**3.21%**	**3.28%**	4.05%	4.30%
Expected long-term return on plan assets	**6.29%**	**3.25%**	6.50%	2.81%
Rate of compensation increase	**3.34%**	**3.70%**	3.30%	3.67%
Health care trend – initial (current year)	**–**	**5.91%**	–	6.39%
– ultimate	**–**	**4.37%**	–	4.45%
– year ultimate reached		**2038**		2035

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.

DEFINED CONTRIBUTION PLAN

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2020 was $45 million (2019 – $34 million).

22. GOODWILL

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

millions of Canadian dollars	**2020**	2019
Balance, January 1	**$ 5,835**	$ 6,313
Additions	**–**	3
GBPC impairment charge	**–**	(30)
Classified as assets held for sale (1)	**–**	(148)
Change in foreign exchange rate	**(115)**	(303)
Balance, December 31	**$ 5,720**	$ 5,835

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

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2020, primarily relates to TECO Energy and GBPC. Emera's reporting units with goodwill are Tampa Electric, PGS, NMGC, and GBPC.

In 2020, Emera performed a qualitative impairment assessment for Tampa Electric, PGS and NMGC, concluding that the fair value of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessment were performed and no impairment charges were recognized.

Goodwill on Emera's Consolidated Balance Sheets at December 31, 2020, included $68 million (2019 – $70 million) related to GBPC. In 2019 Emera recognized an impairment charge of $30 million based on the excess of GBPC's carrying amount over its fair value. The 2019 impairment charge is included in "Impairment charges" in the Consolidated Statements of Income. In 2020, due to the limited excess of fair value over carrying value as a result of the 2019 impairment charge, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment using a discounted cash flow analysis. This assessment estimated that the fair value of the reporting unit exceeded its carrying value, including goodwill, by approximately five per cent. Adverse changes in significant assumptions used could result in a future impairment.

23. 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	**2020**	**Weighted average interest rate**	2019	Weighted average interest rate
Tampa Electric Company ("TEC")				
Advances on accounts receivable and revolving credit facilities	**$ 987**	**0.89%**	$ 452	2.56%
Emera				
Non-revolving term facility	**400**	**0.94%**	399	2.69%
Bank indebtedness	**–**	**-%**	6	-%
TECO Finance				
Advances on revolving credit and term facilities	**205**	**1.46%**	656	2.39%
NMGC				
Advances on revolving credit facilities	**21**	**1.22%**	8	2.70%
GBPC				
Advances on revolving credit facilities	**11**	**5.25%**	10	5.25%
NSPI				
Bank indebtedness	**1**	**-%**	6	-%
Short-term debt	**$ 1,625**		$ 1,537	

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	**2020**	2019
Tampa Electric Company – revolving credit facility	2023	**$ 1,019**	$ 520
TECO Energy/TECO Finance – revolving credit facility	2023	**509**	520
Emera – non-revolving term facility	2021	**400**	400
TEC – term loan	2021	**382**	–
TEC – accounts receivable revolving credit facility	2021	**191**	195
NMGC – revolving credit facility	2023	**159**	162
GBPC – revolving credit facility	on demand	**17**	17
TECO Energy/TECO Finance – term credit facility		**–**	649
Total		**2,677**	2,463
Less:			
Advances under revolving credit and term facilities		**1,624**	1,525
Letters of credit issued within the credit facilities		**4**	3
Total advances under available facilities		**1,628**	1,528
Available capacity under existing agreements		**$ 1,049**	$ 935

The weighted average interest rate on outstanding short-term debt at December 31, 2020 was 1.01 per cent (2019 – 2.54 per cent).

RECENT SIGNIFICANT FINANCING ACTIVITY 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 the London interbank deposit rate ("LIBOR"), prime rate or the federal funds rate, plus a margin. On January 29, 2021, TEC extended the maturity date of the agreement to April 29, 2021 with no other changes in terms.

On December 18, 2020, TEC amended and restated its bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023 and increased the amount of the commitment by the lenders to $800 million USD from $400 million USD. The credit facility bears interest based on either the LIBOR, the Wells Fargo Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $80 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Gas Utilities and Infrastructure

On December 18, 2020, NMGC amended and restated its $125 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The amended facility now includes a $30 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

Other

On February 28, 2020, TECO Finance extended the maturity date of its $500 million USD credit facility from March 5, 2020 to July 3, 2020. There were no other significant changes in commercial terms from the prior agreement. Using funds from the sale of Emera Maine, on April 3, 2020, TECO Finance repaid $200 million USD of the term loan and the remaining $300 million USD was repaid on June 30, 2020.

On December 1, 2020, Emera extended the maturity date of its $400 million non-revolving term loan from December 15, 2020 to December 16, 2021. There were no other significant changes in commercial terms from the prior agreement.

On December 18, 2020, TECO Finance amended and restated its $400 million USD bank credit facility. The amendment extended the maturity date of the credit facility from March 22, 2022 to March 22, 2023. The credit facility bears interest based on either the LIBOR, JP Morgan Chase Bank's prime rate, or the federal funds rate, plus a margin. The facility now includes a $50 million USD letter of credit facility. There were no other significant changes in commercial terms from the prior agreement.

24. OTHER CURRENT LIABILITIES

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Accrued charges	**$ 141**	$ 147
Accrued interest on long-term debt	**71**	77
Pension and post-retirement liabilities (note 21)	**23**	22
Sales and other taxes payable	**6**	13
Income tax payable	**1**	1
Other	**98**	73
	$ 340	$ 333

25. 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) 2020	2019	Maturity	**2020**	2019
Emera					
Bankers acceptances, LIBOR loans	Variable	Variable	2024	**$ 263**	$ 437
Unsecured fixed rate notes	2.90%	2.90%	2023	**500**	500
Fixed to floating subordinated notes (USD)	6.75%	6.75%	2076	**1,528**	1,559
				$ 2,291	$ 2,496
Emera Finance					
Unsecured senior notes (USD)	3.86%	3.86%	2021–2046	**$ 3,501**	$ 3,572
TECO Finance					
Fixed rate notes and bonds (USD)	–	5.15%	–	**–**	390
Tampa Electric (2)					
Fixed rate notes and bonds (USD)	4.53%	4.53%	2021–2050	**$ 3,268**	$ 3,334
PGS					
Fixed rate notes and bonds (USD)	4.58%	4.58%	2021–2050	**$ 429**	$ 437
NMGC					
Fixed rate notes and bonds (USD)	4.30%	4.30%	2021–2049	**$ 465**	$ 474
NMGI					
Fixed rate notes and bonds (USD)	3.64%	3.64%	2024	**$ 191**	$ 195
NSPI					
Discount notes	Variable	Variable	2024	**$ 291**	$ 308
Medium term fixed rate notes	5.14%	5.37%	2025–2097	**2,665**	2,365
				$ 2,956	$ 2,673
Emera Maine					
LIBOR loans and demand loans		Variable		**$ –**	$ 11
Secured fixed rate mortgage bonds (USD)	–	9.74%	–	**–**	65
Unsecured senior fixed rate notes (USD)	–	4.15%	–	**–**	442
				$ –	$ 518
EBP					
Senior secured credit facility	Variable	Variable	2023	**$ 249**	$ 248
ECI					
Secured senior notes (USD)	Variable	Variable	2021–2031	**106**	130
Amortizing fixed rate notes (USD)	3.92%	3.89%	2021–2022	**100**	122
Non-revolving term facility, floating rate	Variable	-	2025	**28**	–
Non-revolving term facility, fixed rate	2.60%	-	2025	**68**	–
Secured fixed rate senior notes (3)	4.39%	4.84%	2022–2035	**$ 174**	$ 218
				$ 476	$ 470
Adjustments					
Fair market value adjustment – TECO Energy acquisition (4)				**$ 5**	$ 8
Debt issuance costs				**(110)**	(119)
Classification as liabilities held for sale (5)				**–**	(516)
Amount due within one year				**(1,382)**	(501)
				$ (1,487)	$ (1,128)
Long-Term Debt				**$ 12,339**	$ 13,679

(1) Weighted average interest rate of fixed rate long-term debt.
(2) 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.
(3) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).
(4) 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.
(5) On March 24, 2020 Emera sold Emera Maine. Refer to note 4 for further detail. As at December 31, 2019, Emera Maine's assets and liabilities are classified as 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	2020	2019
Emera – revolving credit facility (1)	June 2024	**$ 900**	$ 900
NSPI – revolving credit facility (1)	October 2024	**600**	600
ECI – revolving credit facilities	2021-2023	**28**	25
Emera Maine – revolving credit facility		**-**	104
Total		**1,528**	1,629
Less:			
Borrowings under credit facilities		**569**	771
Letters of credit issued inside credit facilities		**31**	65
Use of available facilities		**600**	836
Available capacity under existing agreements		**$ 928**	$ 793

(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, 2020
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.56 : 1

RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

Canadian Electric Utilities

On April 24, 2020, NSPI completed a $300 million 30-year unsecured notes issuance. The notes bear interest at a rate of 3.31 per cent and have a maturity date of April 25, 2050.

Other Electric Utilities

On May 20, 2020, GBPC entered into a $22 million USD non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 90-day LIBOR plus a margin. On May 22, 2020, proceeds from this loan were used to repay $22 million USD senior notes upon maturity.

On May 20, 2020, GBPC entered into a $15 million BSD ($15 million USD) non-revolving term loan with a maturity date of May 20, 2025. The loan bears interest at a rate of 4.00 per cent.

At December 31, 2020, BLPC had drawn $77 million BBD ($38 million USD) against a $110 million BBD ($55 million USD) non-revolving term loan. The loan bears interest at a rate of 2.05 per cent and has a 5-year term.

Gas Utilities and Infrastructure

On February 5, 2021, NMGC completed an issuance of $220 million USD senior notes. The issuance included $70 million USD senior notes that bear interest at a rate of 2.26 per cent with a maturity date of February 5, 2031, $65 million USD senior notes that bear interest at a rate of 2.51 per cent and with a maturity date of February 5, 2036, and $85 million USD senior notes that bear interest at a rate of 3.34 per cent with a maturity date of February 5, 2051. Proceeds from this issuance were used to repay a $200 million USD note, due in 2021 and for general corporate purposes. These notes were classified as long-term debt at December 31, 2020.

Other

On March 13, 2020, TECO Finance repaid a $300 million USD note upon maturity. The note was repaid using existing credit facilities.

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	2021	2022	2023	2024	2025	Thereafter	Total
Emera	$ –	$ –	$ 500	$ 263	$ –	$ 1,528	$ 2,291
Emera US Finance LP	955	–	–	–	–	2,546	3,501
Tampa Electric	295	286	–	–	–	2,687	3,268
PGS	59	33	–	–	–	337	429
NMGC	–	–	–	–	–	465	465
NMGI	–	–	–	191	–	–	191
NSPI	–	–	–	291	125	2,540	2,956
EBP	–	–	249	–	–	–	249
ECI	73	88	60	75	101	79	476
Total	$ 1,382	$ 407	$ 809	$ 820	$ 226	$ 10,182	$ 13,826

26. 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	**2020**	2019
Balance, January 1	**$ 185**	$ 205
Additions	**10**	–
Liabilities settled (1)	**(25)**	(25)
Accretion included in depreciation expense	**9**	7
Accretion deferred to regulatory asset (included in property, plant and equipment)	**(3)**	–
Other	**1**	3
Change in foreign exchange rate	**1**	(5)
Balance, December 31	**$ 178**	$ 185

(1) Tampa Electric produces ash and other by-products, collectively known as CCR's, at its Big Bend and Polk power stations. The decreases in ARO in 2020 and 2019 are due to the closure of CCR management facilities.

27. COMMITMENTS AND CONTINGENCIES

A. COMMITMENTS

As at December 31, 2020, 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	2021	2022	2023	2024	2025	Thereafter	Total
Purchased power (1)	$ 231	$ 218	$ 216	$ 218	$ 224	$ 2,242	$ 3,349
Transportation (2)	518	393	339	306	282	2,704	4,542
Capital projects	394	98	76	–	–	–	568
Fuel, gas supply and storage	494	91	6	1	–	–	592
Long-term service agreements (3)	43	41	36	33	34	92	279
Equity investment commitments (4)	–	240	–	–	–	–	240
Leases and other (5)	16	17	16	15	8	118	190
Demand side management	40	45	–	–	–	–	85
	$ 1,736	$ 1,143	$ 689	$ 573	$ 548	$ 5,156	$ 9,845

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $149 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.
(4) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
(5) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

On March 17, 2020, Nalcor announced that it had paused construction activities at the Muskrat Falls site in response to the COVID-19 pandemic. As a result of the effects of COVID-19 on project execution, Nalcor declared force majeure under various project contracts, including formal notification to NSPML. Nalcor achieved first power on the first of four generators at Muskrat Falls on September 22, 2020 and continues to work toward completing project commissioning in 2021.

NSPML expects to file a final cost assessment with the UARB upon commencement of the NS Block of energy from Muskrat Falls, which is anticipated to take place in 2021. On December 16, 2020, the UARB approved NSPML's 2021 interim assessment for recovery from NSPI of Maritime Link costs of approximately $172 million subject to a holdback of $10 million with similar terms as previously approved by the UARB and potential long-term deferral of up to $23 million in depreciation expense dependent upon the timing of commencement of the NS Block.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. As part of NSPI's 2020-2022 fuel stability plan, rates have been set to include the $145 million approved for 2020 and amounts of $164 million and $162 million for 2021 and 2022, respectively. On December 16, 2020, the UARB approved the 2021 interim cost assessment of approximately $172 million. Any difference between the amounts included in the NSPI fuel stability plan and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are dependent on regulatory filings with the UARB.

Once Muskrat Falls and LIL have achieved full power, the commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties relating to the Maritime Link and LIL.

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 could 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, the obligations are included within "Leases and other" in the above table.

B. LEGAL PROCEEDINGS

TECO Guatemala Holdings ("TGH")

Prior to Emera's acquisition of TECO Energy in 2016, TGH, a wholly owned subsidiary of TECO Energy, divested of its indirect investment that resided in Guatemala. In 2013, the ICSID tribunal hearing an arbitration claim of TGH against the Republic of Guatemala ("Guatemala") under the Dominican Republic Central America – United States Free Trade Agreement, issued an award. The arbitration concerned TGH's allegation that Guatemala unfairly set the distribution tariff for a local distribution company which harmed TGH's investment in that company. The ICSID Tribunal unanimously found in favour of TGH and awarded damages to TGH of approximately $21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus 2 per cent. Subsequent proceedings resulted in Guatemala awards of additional interest and certain costs to TGH (in aggregate, the "First Award"). In November 2020, Guatemala withdrew its appeal in U.S. courts against the enforcement of the First Award and made a payment of approximately $38 million USD in full and final satisfaction of the First Award. This amount was recognized in "Other Income, net" on the Consolidated Statements of Income.

On September 23, 2016, TGH had filed a separate request for resubmission to arbitration seeking damages in addition to those awarded in the First Award. On May 13, 2020, a second tribunal awarded TGH additional damages and costs against Guatemala of more than $35 million USD plus interest (the "Second Award"). TGH subsequently requested a reconsideration of the interest quantum awarded in connection with this Second Award. On October 16, 2020, the tribunal granted TGH's request for additional interest. The additional amount is approximately $2 million USD. Guatemala now has until February 16, 2021 to seek annulment of the Second Award before ICSID. To date, the total of the Second Award, with interest, is approximately $59 million USD. Results to date do not reflect any benefit of the Second Award.

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, 2020, TEC has estimated its financial liability to be $22 million ($17 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

On March 24, 2020, the Company completed the sale of Emera Maine. Emera has no remaining obligations with respect to the legal proceedings previously disclosed in note 26 of Emera's 2019 annual audited consolidated financial statements. No new or additional reserves were made in 2020 with respect to any of the four complaints filed with the FERC.

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 15 and note 16.

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.

Public Health Risk

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company, including causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business.

The extent of the evolving COVID-19 pandemic and its future impact on the Company is uncertain. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat. The Company's top priority continues to be the health and safety of its customers and employees.

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 could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions 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 and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions including those related to public health threats, such as the COVID-19 pandemic.

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. For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks 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.

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 interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Interest rates may be impacted by market disruptions related to public health threats, including the COVID-19 pandemic.

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

The Company's utility fuel supply is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. The Company's commercial arrangements, including the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments are all used to manage and mitigate this risk. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

Regulated Utilities

A large portion of the Company's utility fuel supply comes from international suppliers and therefore 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 using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated utilities have adopted and implemented fuel adjustment mechanisms which has further helped manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Emera Energy Marketing and Trading

Emera Energy has employed further measures to manage commodity risk. 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 value-at-risk ("VaR") analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

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, 2020:

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.

Emera Inc. has issued a guarantee of up to $35 million USD relating to outstanding notes of GBPC. The guarantee for the notes will expire in May 2023.

In 2020, NSPI issued guarantees in the amount of $18 million USD on behalf of its subsidiary, NS Power Energy Marketing Incorporate ("NSPEMI"), to secure obligations under purchase agreements with third-party suppliers. The guarantees have terms of varying lengths and will be renewed as required.

The Company has standby letters of credit and surety bonds in the amount of $55 million USD (December 31, 2019 – $82 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 expiry date of this letter of credit was extended to June 2021. The amount committed as at December 31, 2020 was $63 million (December 31, 2019 – $52 million).

Collaborative Arrangements

For the years ended December 31, 2020 and 2019, 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 2020, NSPI recognized $19 million net expense (2019 – $19 million) in "Regulated fuel for generation and purchased power" and $3 million (2019 – $3 million) in OM&G.

28. CUMULATIVE PREFERRED STOCK

Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

			December 31, 2020		December 31, 2019	
	Annual Dividend per Share	Redemption Price per Share	**Issued and Outstanding**	**Net Proceeds**	Issued and Outstanding	Net Proceeds
Series A	$ 0.6388	$ 25.00	**4,866,814**	**$ 95**	3,864,636	$ 95
Series B	Floating	$ 25.00	**1,133,186**	**$ 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 (5) (6)	4.400	0.5456	1.84	August 15, 2025	25.00	Series B
Series C	4.100	1.1802	2.65	August 15, 2023	25.00	Series D
Series F (7) (8)	4.202	1.0505	2.63	February 15, 2025	25.00	Series G
Minimum rate reset (3) (4)						
Series B (9)	2.393	Floating	1.84	August 15, 2025	25.00	Series A
Series H	4.900	1.2250	4.90	August 15, 2023	25.00	Series I
Perpetual fixed rate						
Series E (10)	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 A was reset from $0.6388 to $0.5456 for the five-year period from and including August 15, 2020.
(6) On July 9, 2020, Emera announced it would not redeem the Cumulative Rate Reset Preferred Shares, Series A or the Cumulative Floating Rate First Preferred Shares, Series B. On August 17, 2020, Emera announced 128,610 of its 3,864,636 issued and outstanding Series A Shares were tendered for conversion into Series B Shares and 1,130,788 of its 2,135,364 issued and outstanding Series B Shares were tendered for conversion into Series A Shares, all on a one-for-one basis. As a result of the conversion, Emera has 4,866,814 Series A Shares and 1,133,186 Series B Shares issued and outstanding.
(7) 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.
(8) The annual fixed dividend per share for First Preferred Shares, Series F was reset from $1.0625 to $1.0505 for the five-year period from and including February 15, 2020.
(9) Emera announced a dividend rate of 2.021 per cent on the Series B Shares for the three-month period which commenced on August 15, 2020 and ended on (and inclusive of) November 14, 2020 ($0.1274 per Series B Share for the quarter.
(10) 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.

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

As at millions of Canadian dollars	**December 31 2020**	December 31 2019
Preferred shares of GBPC	**$ 14**	$ 14
Domlec	**20**	21
	$ 34	$ 35

PREFERRED SHARES OF GBPC:

Authorized:

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

	2020		2019	
Issued and outstanding:	**number of shares**	**millions of dollars**	number of shares	millions of dollars
Outstanding as at December 31	**10,000**	**$ 14**	10,000	$ 14

GBPC NON-VOTING CUMULATIVE VARIABLE PERPETUAL PREFERRED STOCK:

The 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.

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.

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the	Year ended December 31	
millions of Canadian dollars	**2020**	2019
Changes in non-cash working capital:		
Inventory	**$ 6**	$ (19)
Receivables and other current assets	**187**	154
Accounts payable	**55**	(137)
Other current liabilities	**(31)**	(71)
Total non-cash working capital	**$ 217**	$ (73)
Supplemental disclosure of cash paid (received):		
Interest	**$ 679**	$ 750
Income taxes	**$ (148)**	$ (107)
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 199**	$ 187
Reclassification of long-term debt from current to non-current	**$ 256**	$ –
Increase in accrued capital expenditures	**$ 17**	$ 33

31. 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, 2020, the plan allows employees to make cash contributions of a minimum of $25 to a maximum of $20,000 Canadian dollars or $15,000 US dollars per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows the reinvestment of dividends for all participants except for where it is prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares (2019 – 4 million common shares). As at December 31, 2020, Emera is in compliance with this requirement.

Compensation cost for shares issued by Emera for the year ended December 31, 2020 under the Employee Common Share Purchase Plan was $2 million (2019 – $1 million) and is included in OM&G on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan") or ("DRIP"), which provides an opportunity for shareholders to reinvest dividends 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. The discount was 2 per cent in 2020. Effective with the dividend payment of August 15, 2019, the discount changed from 5 per cent to 2 per cent.

STOCK-BASED COMPENSATION PLANS

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 11.7 million shares. As at December 31, 2020, 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 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

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:

	2020	2019
Weighted average fair value per option	**$ 3.58**	$ 2.41
Expected term (1)	**5 years**	6 years
Risk-free interest rate (2)	**1.33%**	1.82%
Expected dividend yield (3)	**4.09%**	5.10%
Expected volatility (4)	**14.10%**	14.32%

(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 2020:

	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, 2019	2,286,550	$ 43.31	1,549,025	$ 2.22
Granted	501,900	60.03	501,900	3.58
Exercised	(417,968)	44.74	N/A	N/A
Vested	N/A	N/A	(654,375)	2.32
Forfeited	(102,700)	45.94	(102,700)	2.33
Options outstanding December 31, 2020	**2,267,782**	**$ 46.62**	**1,293,850**	**$ 2.69**
Options exercisable December 31, 2020 (2) (3)	**973,932**	**$ 42.08**		

(1) As at December 31, 2020, 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 3 years (2019 – $2 million, 2 years).
(2) As at December 31, 2020, the weighted average remaining term of vested options was 6 years with an aggregate intrinsic value of $12 million (2019 – 6 years, $11 million).
(3) As at December 31, 2020, the fair value of options that vested in the year was $2 million (2019 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2020 was $1 million (2019 – $1 million), which is included in OM&G on the Consolidated Statements of Income.

As at December 31, 2020, cash received from option exercises was $19 million (2019 – $97 million). The total intrinsic value of options exercised for the year ended December 31, 2020 was $6 million (2019 – $32 million). The range of exercise prices for the options outstanding as at December 31, 2020 was $32.06 to $60.03 (2019 – $32.06 to $46.39).

SHARE UNIT PLANS

The Company has Deferred Share Unit Plan ("DSU"), Performance Share Unit Plan ("PSU") and Restricted Share Unit Plan ("RSU") plans and the liabilities are marked-to-market at the end of each period based on an average 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 by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2020 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, 2019	704,597	$ 34.69	531,454	$ 39.96
Granted including DRIP	84,790	47.74	93,008	51.65
Exercised	(127,389)	30.50	(33,338)	41.89
Outstanding and exercisable as at December 31, 2020	**661,998**	**$ 37.17**	**591,124**	**$ 41.69**

Compensation cost recognized for employee and director DSU's for the year ended December 31, 2020 was $2 million (2019 – $24 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were $1 million (2019 – $7 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2020 for employees was $36 million (2019 – $40 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2020 for directors was $32 million (2019 – $30 million). Cash payments made during the year ended December 31, 2020 associated with the DSU plan was $11 million (2019 – $22 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 the payouts 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, 2020 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value
Outstanding as at December 31, 2019	1,381,100	$ 45.37	$ 88
Granted including DRIP	271,185	53.14	
Exercised	(445,066)	45.41	
Forfeited	(80,690)	46.25	
Outstanding as at December 31, 2020	**1,126,529**	**$ 47.16**	**$ 68**

Compensation cost recognized for the PSU plan for the year ended December 31, 2020 was $27 million (2019 – $34 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were $7 million (2019 – $9 million). Cash payments made during the year ended December 31, 2020 associated with the PSU plan was $29 million (2019 – $7 million).

Restricted Share Unit Plan

In 2020, Emera introduced an RSU plan, where certain executive and senior employees are eligible for long-term incentives payable through the RSU plan. RSUs are granted annually for three-year overlapping performance 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 the payouts 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 RSUs for the year ended December 31, 2020 is presented in the following table:

	Employee RSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value
Outstanding as at December 31, 2019	–	$ –	$ –
Granted including DRIP	171,908	54.62	
Forfeited	(5,633)	54.62	
Outstanding as at December 31, 2020	**166,275**	**$ 54.62**	**$ 10**

Compensation cost recognized for the RSU plan for the year ended December 31, 2020 was $4 million (2019 – nil). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2020 were $1 million (2019 – nil). Cash payments made during the year ended December 31, 2020 associated with the RSU plan was nil (2019 – nil).

32. VARIABLE INTEREST ENTITIES

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. 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, 2020**		December 31, 2019	
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)	**$ 547**	**$ 16**	$ 554	$ 23

33. 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.

34. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 16, 2021, the date the financial statements were issued.

35. 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, 2020						
Operating revenues	$ (1)	$ –	$ 3,456	$ 2,070	$ (19)	**$ 5,506**
Operating expenses	51	–	2,640	1,688	(20)	**4,359**
Income (loss) from equity investments and subsidiaries	1,049	–	1	147	(1,048)	**149**
Other income (expenses), net	20	–	687	1	–	**708**
Interest expense, net (1)	48	(37)	448	220	–	**679**
Income (loss) before provision for income taxes	969	37	1,056	310	(1,047)	**1,325**
Income tax expense (recovery)	(14)	(1)	348	7	1	**341**
Net income (loss)	983	38	708	303	(1,048)	**984**
Non-controlling interest in subsidiaries	–	–	–	–	1	**1**
Preferred stock dividends	45	–	–	1	(1)	**45**
Net income (loss) attributable to common shareholders	$ 938	$ 38	$ 708	$ 302	$ (1,048)	**$ 938**
Comprehensive income (loss) of Emera Incorporated	$ 809	$ 35	$ 575	$ 257	$ (867)	**$ 809**
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

(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, 2020						
Assets						
Current assets	$ 121	$ 10	$ 1,216	$ 1,010	$ (179)	**$ 2,178**
Property, plant and equipment	21	–	14,356	5,164	(6)	**19,535**
Other assets						
Regulatory assets	–	–	520	899	–	**1,419**
Goodwill	3	–	5,648	69	–	**5,720**
Other long-term assets	12,522	4,591	130	3,254	(18,115)	**2,382**
Total other assets	12,525	4,591	6,298	4,222	(18,115)	**9,521**
Total assets	$ 12,667	$ 4,601	$ 21,870	$ 10,396	$ (18,300)	**$ 31,234**
Liabilities and Equity						
Current liabilities	$ 554	$ 2,024	$ 4,121	$ 723	$ (2,547)	**$ 4,875**
Long-term liabilities						
Long-term debt	2,210	2,513	4,026	3,590	–	**12,339**
Deferred income taxes	–	2	852	761	14	**1,629**
Regulatory liabilities	–	–	1,747	85	–	**1,832**
Other long-term liabilities	700	–	4,510	1,666	(5,555)	**1,321**
Total long-term liabilities	2,910	2,515	11,135	6,102	(5,541)	**17,121**
Total Emera Incorporated equity	9,203	62	6,614	3,550	(10,225)	**9,204**
Non-controlling interest in subsidiaries	–	–	–	21	13	**34**
Total equity	9,203	62	6,614	3,571	(10,212)	**9,238**
Total liabilities and equity	$ 12,667	$ 4,601	$ 21,870	$ 10,396	$ (18,300)	**$ 31,234**
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

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, 2020						
Net cash provided by (used in) operating activities	$ 365	$ 36	$ 1,277	$ 486	$ (527)	**$ 1,637**
Investing activities						
Additions to property, plant and equipment	(1)	–	(2,150)	(472)	–	**(2,623)**
Proceeds on disposal of assets	–	–	1,401	–	–	**1,401**
Other investing activities	(118)	265	546	100	(795)	**(2)**
Net cash provided by (used in) investing activities	(119)	265	(203)	(372)	(795)	**(1,224)**
Financing activities						
Change in short-term debt, net	(6)	–	107	(5)	–	**96**
Proceeds from long-term debt	–	–	173	429	(174)	**428**
Retirement of long-term debt	–	–	(705)	(87)	279	**(513)**
Net borrowings (repayments) under committed credit facilities	(82)	–	8	(157)	28	**(203)**
Issuance of common and preferred stock	285	(241)	(3)	53	191	**285**
Dividends paid	(454)	(66)	(80)	(379)	525	**(454)**
Other financing activities	(18)	(4)	(494)	32	473	**(11)**
Net cash provided by (used in) financing activities	(275)	(311)	(994)	(114)	1,322	**(372)**
Effect of exchange rate changes on cash, cash equivalents, restricted cash and assets held for sale	18	(8)	(70)	(1)	–	**(61)**
Net increase (decrease) in cash, cash equivalents, restricted cash and assets held for sale	(11)	(18)	10	(1)	–	**(20)**
Cash, cash equivalents and restricted cash, beginning of year	1	19	87	167	–	**274**
Cash, cash equivalents, restricted cash and assets held for sale, end of year	$ (10)	$ 1	$ 97	$ 166	$ –	**$ 254**

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, 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 significant influence and held-for-trading common shares	–	–	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 and restricted cash	147	(3)	(141)	(23)	–	(20)
Net increase (decrease) in cash, cash equivalents and restricted cash	(25)	(39)	(17)	(17)	–	(98)
Cash, cash equivalents and restricted cash, beginning of year	20	58	104	190	–	372
Cash, cash equivalents and restricted cash, end of year	$ (5)	$ 19	$ 87	$ 173	$ –	$ 274

EMERA LEADERSHIP AND BOARD

As of March 31, 2021

EMERA LEADERSHIP

Scott Balfour
President and
Chief Executive Officer,
Emera Inc.

Rob Bennett
President and Chief
Executive Officer,
Emera Technologies

Greg Blunden
Chief Financial Officer,
Emera Inc.

Archie Collins
President and Chief
Operating Officer,
Tampa Electric

Peter Gregg
President and Chief
Executive Officer,
Nova Scotia Power

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

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

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.

Michael Roberts
Chief Human Resources
Officer,
Emera Inc.

Ryan Shell
President,
New Mexico Gas

Judy Steele
President and
Chief Operating Officer,
Emera Energy

T.J. Szelistowski
President,
Peoples Gas

Nancy Tower
Chief Executive Officer,
Tampa Electric

BOARD OF DIRECTORS

Jackie Sheppard
Calgary, Alberta
Chair, Emera Inc.

Scott Balfour
Halifax, Nova Scotia

James Bertram
Calgary, Alberta

Sylvia Chrominska
Stratford, Ontario

Henry Demone
Lunenburg, Nova Scotia

Kent Harvey
New York, New York

Lynn Loewen
Westmount, Quebec

John Ramil
Tampa, Florida

Andrea Rosen
Toronto, Ontario

Richard Sergel
Boston, Massachusetts

Karen Sheriff
Toronto, Ontario

Jochen Tilk
Toronto, Ontario

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 2020 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

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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: 251,430,226 (as of December 31, 2020)

DIVIDENDS PAID IN 2020

Emera Inc. paid common share dividends at an annualized rate of $2.45 per common share ($0.6125 per quarter) in Q1, Q2 and Q3 and $2.55 ($0.6375 per quarter) in Q4, for an effective annual common share dividend rate of $2.475 per common share.

DIVIDEND PAYMENTS IN 2021

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 $0.6375, a Series A First Preferred Share dividend of $0.1364, a Series B First Preferred Share dividend of $0.1223, 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 $0.26263 and a Series H First Preferred Share dividend of $0.30625 were declared and paid on February 16, 2021.

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. In 2020, the discount was two per cent. Plan participants may also contribute cash payments of up to $5,000 per quarter. Participants of the plan pay no commissions, service charges or brokerage fees for shares purchased under the plan. Please contact Investor Services if you have questions or wish to receive an enrollment form.

DIRECT DEPOSIT SERVICE

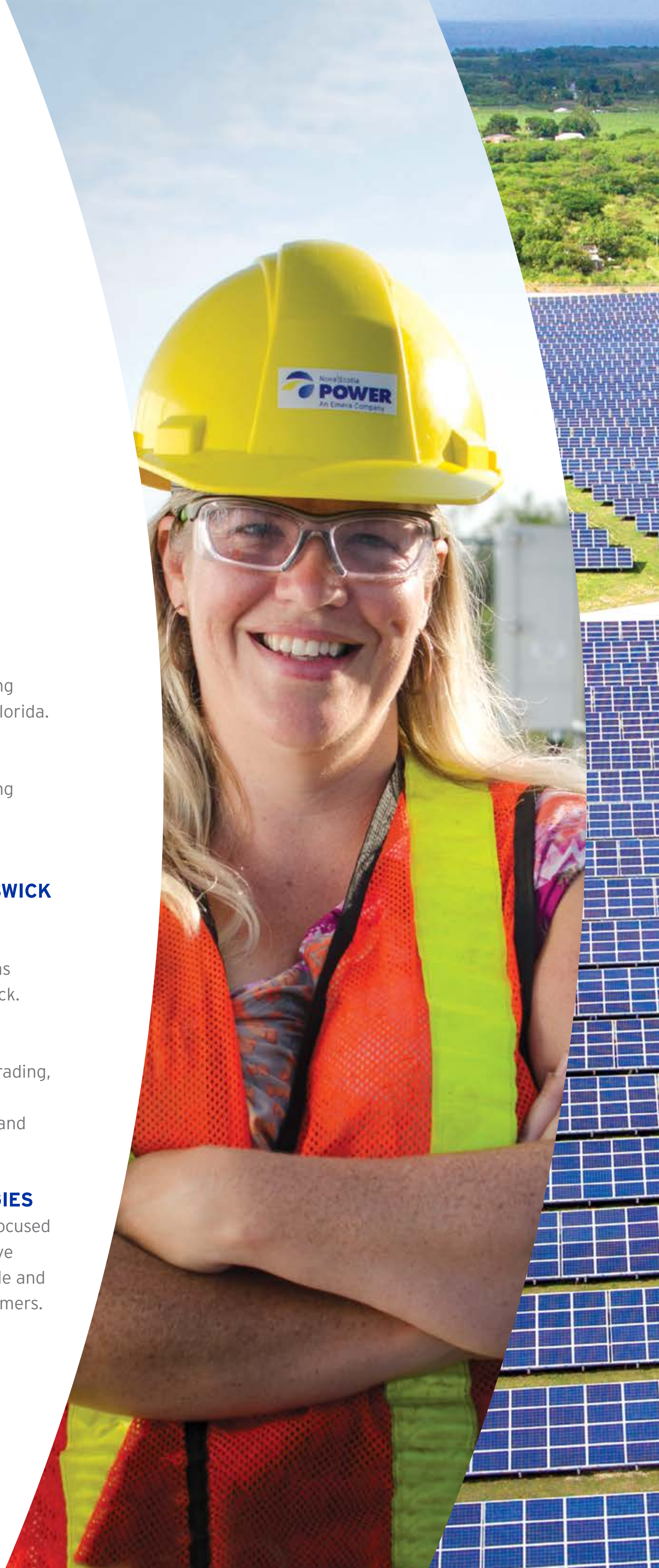
Registered shareholders may have dividends deposited directly to any bank account in Canada. To arrange this service, please contact AST Trust Company (Canada). Beneficial shareholders should contact their financial intermediary.

QUARTERLY EARNINGS

Quarterly earnings are expected to be announced May, August and November 2021. Year-end results for 2020 were released in February 2021.

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

Emera



TAMPA ELECTRIC
Vertically integrated electric utility serving approximately 800,000 customers in west central Florida.

NOVA SCOTIA POWER
Vertically integrated electric utility serving 525,000 customers in Nova Scotia.

EMERA NEWFOUNDLAND & LABRADOR
Owns and operates the Maritime Link and manages Emera's investment in an associated project.

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

PEOPLES GAS
Natural gas utility serving 426,000 customers in Florida.

NEW MEXICO GAS
Natural gas utility serving 540,000 customers in New Mexico.

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

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

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

www.emera.com