Management’s Discussion & Analysis

As at November 9, 2021

Management’s Discussion & Analysis (“MD&A”) provides a review of the results of operations of Emera Incorporated and its subsidiaries and investments during the third quarter and year-to-date of 2021 relative to the same periods in 2020; and its financial position as at September 30, 2021 relative to December 31, 2020. 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 unaudited condensed consolidated interim financial statements and supporting notes as at and for the three and nine months ended September 30, 2021; and the Emera Incorporated annual MD&A and 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 September 30, 2021, 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" section.

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.

TABLE OF CONTENTS

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 dioxide 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 safely delivering 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 2023. The capital investment plan continues to include significant investments across the portfolio in renewable and cleaner generation, reliability and integrity investments, 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 are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and at-the-market program. Maintaining investment-grade credit ratings is a priority of management.

Emera has provided annual dividend growth guidance of four to five per cent through 2024. 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 of 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 dioxide 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 dioxide 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 dioxide emissions by 2040.

Emera seeks to deliver on its Climate Commitment while maintaining its focus on investing in reliability and never losing sight of affordability for customers. Emera is also committed to identifying emerging technologies and continuing to work constructively with policymakers, regulators, partners, investors and customers to achieve these goals and realize its net-zero vision.

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, impacts in 2020 of the gain on sale of Emera Maine and impairment charges on certain other assets.

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, and the related amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the MTM adjustments included in Emera's equity income related to the business activities of Bear Swamp Power Company LLC ("Bear Swamp");
- 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", "Financial Highlights – Other Electric", and the "Financial Highlights – Other" sections.

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. For further details, refer to the "Significant Items Affecting Earnings" section. While the gain on sale has been excluded from adjusted earnings, earnings for the Other Electric Utilities segment includes earnings from Emera Maine up to the date of its sale on March 24, 2020.

In 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" and "Financial Highlights – Other" sections.

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

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Net income (loss) attributable to common shareholders	**$ (70)**	$ 84	**$ 186**	$ 665
Gain on sale, net of tax and transaction costs	**-**	-	**-**	309
Impairment charges, net of tax	**-**	-	**-**	(26)
After-tax MTM loss	**(245)**	(82)	**(369)**	(95)
Adjusted net income attributable to common shareholders	**$ 175**	$ 166	**$ 555**	$ 477
Earnings (loss) per common share – basic	**$ (0.27)**	$ 0.34	**$ 0.73**	$ 2.70
Adjusted earnings per common share – basic	**$ 0.68**	$ 0.67	**$ 2.17**	$ 1.93

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 adjustments, the gain on sale of Emera Maine and impairment charges.

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 (loss) 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 (loss) to EBITDA and Adjusted EBITDA:

For the millions of Canadian dollars	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Net income (loss) (1)	**$ (56)**	$ 84	**$ 223**	$ 700
Interest expense, net	**150**	163	**460**	520
Income tax expense (recovery)	**(92)**	(21)	**(91)**	284
Depreciation and amortization	**228**	217	**675**	664
EBITDA	**230**	443	**1,267**	2,168
Gain on sale, net of transaction costs (excluding income tax)	**-**	-	**-**	585
Impairment charge, excluding income tax	**-**	-	**-**	(25)
MTM loss, excluding income tax	**(345)**	(116)	**(518)**	(136)
Adjusted EBITDA	**$ 575**	$ 559	**$ 1,785**	$ 1,744

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

CONSOLIDATED FINANCIAL REVIEW

Significant Items Affecting Earnings

Earnings Impact of After-Tax MTM Losses

After-tax MTM losses increased $163 million to $245 million in Q3 2021, compared to $82 million in Q3 2020 primarily due to higher forward pricing for New England gas compared to transport hedges in place at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges. This is partially offset by a larger reversal of MTM losses in Q3 2021 at Emera Energy. Year-to-date, after-tax MTM losses increased $274 million to $369 million compared to $95 million for the same period in 2020 due to higher forward pricing for New England gas compared to transport hedges in place at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges, partially offset by lower amortization of gas transportation assets in 2021 at Emera Energy.

2020 Gain on Sale 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 Condensed Consolidated Statements of Income.

In addition, impairment charges of $25 million ($26 million after tax) year-to-date were recognized on certain other assets.

Consolidated Financial Highlights by Business Segment

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
Adjusted net income	**2021**	2020	**2021**	2020
Florida Electric Utility	**$ 169**	$ 175	**$ 377**	$ 400
Canadian Electric Utilities	**42**	35	**174**	164
Other Electric Utilities	**8**	6	**15**	25
Gas Utilities and Infrastructure	**29**	20	**143**	117
Other	**(73)**	(70)	**(154)**	(229)
Adjusted net income attributable to common shareholders	**$ 175**	$ 166	**$ 555**	$ 477
Gain on sale, net of tax and transaction costs	**-**	-	**-**	309
Impairment charges, net of tax	**-**	-	**-**	(26)
After-tax MTM loss	**(245)**	(82)	**(369)**	(95)
Net income (loss) attributable to common shareholders	**$ (70)**	$ 84	**$ 186**	$ 665

The following table highlights significant changes in adjusted net income attributable to common shareholders from 2020 to 2021:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Adjusted net income – 2020	**$**	**166**	**$**	**477**
Operating Unit Performance				
Increased earnings at PGS due to higher base revenues as a result of a base rate increase on January 1, 2021 and customer growth		9		26
Increased earnings at NSPI due to decreased income tax expense and lower interest on the Fuel Adjustment Mechanism ("FAM") regulatory deferral. This was partially offset by lower Maritime Link assessment included in revenue compared to 2020 and higher operating, maintenance and general ("OM&G") expense		7		8
Increased earnings at Emera Energy Services ("EES") due to favourable market conditions		4		28
Decreased earnings at Tampa Electric due to the impact of a stronger CAD. Excluding the impact of foreign exchange, earnings increased due to higher allowance for funds used during construction ("AFUDC"), partially offset by higher depreciation and amortization reflecting increased capital investment and a 2020 regulatory settlement		(6)		(23)
Decreased earnings due to the sale of Emera Maine in Q1 2020		-		(6)
Tax Related				
Revaluation of Corporate, NSPI and Emera Energy net deferred income tax assets and liabilities in Q1 2020 due to the reduction in the Nova Scotia provincial corporate income tax rate		-		14
Recognition of corporate income tax recovery in Q1 2020 previously deferred as a regulatory liability in 2018 at BLPC		-		(10)
Corporate				
Decreased interest expense, pre-tax, due to the impact of a stronger CAD and lower interest rates. Year-over year also due to repayment of corporate debt		7		29
Realized gain on hedges entered into to hedge foreign exchange earnings exposure		4		17
Decreased quarter-over-quarter due to the timing of preferred dividend declaration in Q2 2020		(14)		(2)
Other Variances		(2)		(3)
Adjusted net income – 2021	**$**	**175**	**$**	**555**

For further details of reportable segments contributions, refer to the "Financial Highlights" section.

For the millions of Canadian dollars	Nine months ended September 30 **2021**			2020
Operating cash flow before changes in working capital	**$**	**1,035**	$	1,101
Change in working capital		**71**		139
Operating cash flow	**$**	**1,106**	$	1,240
Investing cash flow	**$**	**(1,576)**	$	(536)
Financing cash flow	**$**	**693**	$	(595)

For further discussion of cash flow, refer to the "Consolidated Cash Flow Highlights" section.

As at millions of Canadian dollars		**September 30 2021**		December 31 2020
Total assets	**$**	**33,242**	$	31,234
Total long-term debt (including current portion)	**$**	**14,436**	$	13,721

Consolidated Income Statement Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30 **2021**	 2020	 Variance	Nine months ended September 30 **2021**	 2020	 Variance
Operating revenues	**$ 1,148**	$ 1,163	$ (15)	**$ 3,897**	$ 3,969	$ (72)
Operating expenses	**1,201**	990	(211)	**3,483**	3,211	(272)
Income (loss) from operations	**(53)**	173	(226)	**414**	758	(344)
Income from equity investments	**33**	32	1	**111**	113	(2)
Other income, net	**22**	21	1	**67**	633	(566)
Interest expense, net	**150**	163	13	**460**	520	60
Income tax expense (recovery)	**(92)**	(21)	71	**(91)**	284	375
Net income (loss)	**$ (56)**	$ 84	$ (140)	**$ 223**	$ 700	$ (477)
Net income (loss) attributable to common shareholders	**$ (70)**	$ 84	$ (154)	**$ 186**	$ 665	$ (479)
Gain on sale, net of tax and transaction costs	**-**	-	-	**-**	309	(309)
Impairment charges, net of tax	**-**	-	-	**-**	(26)	26
After-tax MTM loss	**(245)**	(82)	(163)	**(369)**	(95)	(274)
Adjusted net income attributable to common shareholders	**$ 175**	$ 166	$ 9	**$ 555**	$ 477	$ 78
Earnings (loss) per common share – basic	**$ (0.27)**	$ 0.34	$ (0.61)	**$ 0.73**	$ 2.70	$ (1.97)
Earnings (loss) per common share – diluted	**$ (0.27)**	$ 0.34	$ (0.61)	**$ 0.73**	$ 2.69	$ (1.96)
Adjusted earnings per common share – basic	**$ 0.68**	$ 0.67	$ 0.01	**$ 2.17**	$ 1.93	$ 0.24
Dividends per common share	**$ 0.6375**	$ -	$ 0.63750	**$ 1.9125**	$ 1.8375	$ 0.07500
Adjusted EBITDA	**$ 575**	$ 559	$ 16	**$ 1,785**	$ 1,744	$ 41

Operating Revenues

For the third quarter of 2021, operating revenues decreased $15 million compared to the third quarter in 2020. Absent increased MTM losses of $209 million, operating revenues increased $194 million due to:

- $124 million increase in the Florida Electric Utility segment due to higher fuel recovery clause revenue as a result of higher fuel costs, partially offset by the impact of a stronger CAD;
- $45 million increase in the Gas Utilities and Infrastructure segment due to base rate increases at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices. This increase was partially offset by the impact of a stronger CAD;
- $15 million increase in the Other Electric Utilities segment due to higher fuel revenue at BLPC as a result of higher sales volumes and higher fuel prices; and
- $8 million increase in the Other segment due to higher marketing and trading margin at EES primarily driven by favourable market conditions.

Year-to-date in 2021, operating revenues decreased $72 million compared to the same period in 2020. Absent increased MTM losses of $353 million, operating revenues increased by $281 million due to:

- $148 million increase in the Florida Electric Utility segment primarily due to higher fuel recovery clause revenue as a result of higher fuel costs, partially offset by the impact of a stronger CAD;
- $141 million increase in the Gas Utilities and Infrastructure segment due to base rate increases at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices. This increase was partially offset by the impact of a stronger CAD; and
- $47 million increase in the Other segment due to higher marketing and trading margin at EES primarily driven by favourable market conditions.

These impacts were partially offset by:

- $59 million decrease in the Other Electric Utilities segment due to the sale of Emera Maine in Q1 2020.

Operating Expenses

For the third quarter of 2021, operating expenses increased $211 million compared to the third quarter of 2020. Operating expenses increased due to:

- $145 million increase in the Florida Electric Utility segment due to higher natural gas prices, partially offset by the impact of a stronger CAD;
- $36 million increase in the Gas Utilities and Infrastructure segment due to higher gas prices at PGS and NMGC, partially offset by the impact of a stronger CAD; and
- $16 million increase in the Other Electric Utilities segment due to higher fuel prices at BLPC.

Year-to-date in 2021, operating expenses increased $272 million compared to the same period of 2020. Absent the 2020 impairment charges of $26 million, operating expenses increased $298 million due to:

- $210 million increase in the Florida Electric Utility segment due to higher natural gas prices, partially offset by the impact of a stronger CAD; and
- $114 million increase in the Gas Utilities and Infrastructure segment due to higher gas prices at PGS and NMGC, partially offset by the impact of a stronger CAD.

These impacts were partially offset by:

- $48 million decrease in the Other Electric Utilities segment primarily due to the sale of Emera Maine in Q1 2020.

Other Income, Net

Other income, net decreased year-to-date in 2021 compared to the same period in 2020 primarily due to the 2020 pre-tax gain on sale of Emera Maine.

Interest Expense, Net

Interest expense, net decreased for the third quarter and year-to-date 2021, compared to the same periods in 2020, due to the impact of a stronger CAD and lower interest rates. Year-over-year also decreased due to the repayment of long-term corporate debt.

Income Tax Expense (Recovery)

The increase in income tax recovery for the third quarter in 2021, compared to the same period in 2020, was primarily due to decreased income before provision for income taxes. The decrease in income tax expense year-to-date in 2021, compared to the same period in 2020, was primarily due to the gain on sale of Emera Maine.

Net Income and Adjusted Net Income Attributable to Common Shareholders

For the third quarter of 2021, the decrease in net income attributable to common shareholders compared to the same period in 2020, was unfavourably impacted by the $163 million increase in after-tax MTM losses primarily due to higher forward pricing for New England gas compared to transport hedges in place at Emera Energy. Absent the unfavourable MTM changes, adjusted net income attributable to common shareholders increased $9 million. The increase was primarily due to increased earnings contributions from PGS and EES, lower corporate interest expense, and lower income tax expense at NSPI. These were partially offset by the timing of the preferred dividend declaration in Q2 2020, and the impact of a stronger CAD on the translation of foreign affiliates.

Year-to-date in 2021, net income attributable to common shareholders, compared to the same period in 2020, was unfavourably impacted by the $309 million after-tax gain on sale of Emera Maine in 2020, unfavourably impacted by the $274 million increase in after-tax MTM losses primarily related to Emera Energy as noted above, and favourably impacted by the $26 million after-tax impairment charge in 2020. Absent the net gain on sale of Emera Maine in 2020, the unfavourable MTM changes and the 2020 impairment charges, adjusted net income attributable to common shareholders increased $78 million. The increase was primarily due to lower corporate interest expense, higher earnings contribution from EES and PGS, realized gains on foreign exchange hedges, the 2020 revaluation of deferred taxes due to a reduction in the Nova Scotia corporate income tax rate, and lower income tax expense at NSPI. The increase was partially offset by the impact of a stronger CAD on the translation of foreign affiliates, the 2020 recognition of a corporate income tax recovery previously deferred as a regulatory liability in 2018 at BLPC, and lower earnings due to the sale of Emera Maine in Q1 2020.

Earnings and Adjusted Earnings per Common Share – Basic

Earnings per common share – basic were lower for the third quarter and year-to-date in 2021 due to the decreased earnings as discussed above and the impact of the increase in weighted average shares outstanding.

Adjusted earnings per common share were higher for the third quarter and year-to-date in 2021 due to increased adjusted earnings as discussed above, partially offset by the impact of the increase in weighted average shares outstanding.

Effect of Foreign Currency Translation

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

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 entered foreign exchange cash flow hedges 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 2021 and 2020 are as follows:

	Three months ended September 30		Nine months ended September 30		Year ended December 31
For the	**2021**	2020	**2021**	2020	2020
Weighted average CAD/USD exchange rate	**$ 1.28**	$ 1.33	**$ 1.27**	$ 1.35	$ 1.34
Period end CAD/USD exchange rate	**$ 1.27**	$ 1.33	**$ 1.27**	$ 1.33	$ 1.27

Strengthening of the CAD decreased the net loss by $2 million and decreased adjusted earnings by $7 million in Q3 2021, compared to Q3 2020. The strengthening of the CAD decreased earnings by $7 million and adjusted earnings by $27 million year-to-date in 2021, compared to the same period in 2020.

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.

For the millions of US dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Florida Electric Utility	**$ 135**	$ 131	**$ 302**	$ 296
Other Electric Utilities	**6**	5	**12**	19
Gas Utilities and Infrastructure (1)	**16**	8	**93**	67
	157	144	**407**	382
Other segment (2)	**(39)**	(44)	**(78)**	(107)
Total	**$ 118**	$ 100	**$ 329**	$ 275

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt

BUSINESS OVERVIEW AND OUTLOOK

COVID-19 Pandemic

The Company's priorities continue to be the reliable delivery of essential energy services to meet customers' demands while maintaining the health and safety of its customers and employees and supporting the communities in which Emera operates.

While the ongoing COVID-19 pandemic continues to have varying effects on the service territories in which Emera operates, on a consolidated basis, COVID-19 has not had a material financial impact to date on net earnings in 2021. Capital project delays and supply chain disruptions have also been minimal. The Company continues to monitor developments, economic conditions and recommendations by local and national public health authorities related to COVID-19 and is adjusting operational requirements as needed.

The extent of the future impact of COVID-19 on the Company's financial results and business operations cannot be predicted at this time but is not expected to have a material financial impact in 2021. Future impacts will depend on a variety of factors, including the duration and severity of the pandemic, timing and effectiveness of vaccinations, further government actions and future economic activity and energy usage. For further information on the potential future impacts of COVID-19 on Emera and its businesses, refer to the "Business Overview and Outlook" and "Liquidity and Capital Resources" sections in the Company's 2020 annual MD&A.

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.

Refer to the outlook sections by segment below, for affiliate specific impacts, if applicable.

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.

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

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a settlement agreement (the "Settlement Agreement") by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including, Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. It also provides for a 25 basis point increase in the allowed ROE range and mid-point, and $10 million USD of additional revenue, if U.S. Treasury Bond yields exceed a specific threshold set on the date the FPSC votes to approve the agreement. Under the agreement, base rates will not further change from January 1, 2022 through December 31, 2024, unless Tampa Electric's earned ROE were to fall below the bottom of the range during that time. The Settlement Agreement contains a provision whereby Tampa Electric agrees to quantify the future impact of a change in tax rates on net operating income through a reduction or increase in base revenues within 180 days of when such tax change becomes law or its effective date. On October 21, 2021, the FPSC approved the settlement agreement and the final order, reflecting such approval, is expected to be issued in November 2021.

On July 19, 2021, Tampa Electric requested a mid-course adjustment of $83 million USD to its fuel and capacity charges, effective with September 2021 customer bills, due to an increase in fuel commodity and capacity costs in 2021. On August 3, 2021, the FPSC approved the request to recover the costs during the months of September through December 2021.

In 2021, capital investment in the Florida Electric Utility segment is expected to be approximately $1.1 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 Emera Newfoundland & Labrador Holdings Inc. ("ENL"). NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and is 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

NSPI anticipates earning near the low end of its allowed ROE range in 2021 and expects rate base and earnings to be higher than 2020. Assuming normal weather and a modest economic recovery from impacts of the COVID-19 pandemic in 2021, NSPI expects sales volumes to be higher than 2020.

In Q1 2021, NSPI received its 2021 granted emissions allowances under the Nova Scotia Cap-and-Trade Program Regulations. These 2021 allowances will be used in 2021 or allocated within the initial four-year compliance period that ends in 2022. With the commencement of the Nova Scotia block ("NS Block"), which is described below, NSPI is on track to meet the requirements of the program, where compliance is forecasted to be achieved through the granted emissions allowances, reduced emissions and credit purchases under the Cap-and-Trade 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.

Energy from renewable sources has increased with Nalcor Energy's ("Nalcor") commencement of the NS Block of energy from the Muskrat Falls hydroelectric project ("Muskrat Falls") effective August 15, 2021. Nalcor will provide NSPI with approximately 900 GWh of energy annually over 35 years. In addition, for the first five 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. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related interruptions in supply with any resultant delivery shortfalls being delivered at a later date. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. Pursuant to the Energy Access Agreement, Nalcor is obligated to offer NSPI a minimum average of 1.2 TWh of energy annually. Nalcor continues to advance towards construction completion of the Lower Churchill projects (including Muskrat Falls and LIL) with final commissioning targeted for Q1 2022.

Under the provincially legislated Renewable Energy Regulations, 40 per cent of electric sales must be generated from renewable sources. Due to the delay of the NS Block, the provincial government provided NSPI with an alternative compliance plan in 2020, as permitted by the legislation. The alternative compliance plan 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.

There have been several recent environmental developments at both the federal and provincial levels, as described further below. These developments are consistent with NSPI's decarbonization strategy and will facilitate an accelerated transition to cleaner energy. NSPI is engaging with the federal and provincial government, customers and stakeholders to work towards achieving these requirements, goals and targets with a focus on customer affordability.

On November 5, 2021, the Nova Scotia provincial government enacted Bill 57, "Environmental Goals and Climate Change Reduction Act," which signals the provincial government's intent to implement several climate change related goals and greenhouse gas reduction targets, many of which overlap with and replace provisions of pre-existing acts. The bill also introduces a goal to phase out coal-fired electricity generation in Nova Scotia by 2030. Subsequent provincial regulations will be required to detail how these goals and targets will be achieved.

On August 5, 2021, the federal government issued an update to the Pan-Canadian Framework on Clean Growth and Climate Change under the "Greenhouse Gas Pollution Pricing Act". This update (the "Federal Benchmark") applies to the 2023 to 2030 period and puts in place the legal mechanism for increasing the carbon tax in Canada by $15 per tonne annually and reaching $170 per tonne by 2030. It also outlines the minimum compliance criteria for recognizing systems like the Nova Scotia Cap-and-Trade Program to be considered equivalent to the Federal Benchmark.

On July 9, 2021, the Nova Scotia provincial government amended the Renewable Electricity Regulations, mandating that 80 per cent of electric sales be generated from renewable sources by 2030.

On June 29, 2021, the federal government enacted Bill C-12 “Canadian Net-Zero Emissions Accountability Act” with the objective of attaining net-zero emissions by 2050.

In 2021, capital investment for NSPI is expected to be approximately $400 million (2020 – $316 million), including AFUDC, primarily in capital projects required to support system reliability and hydroelectric infrastructure renewal projects.

ENL

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 Condensed Consolidated Balance Sheets.

NSPML

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.

The Maritime Link assets entered service on January 15, 2018 and provide for the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. The Maritime Link will transmit at greater capacity when the Lower Churchill project is complete.

NSPML has UARB approval to collect up to $172 million (2020 - $145 million) from NSPI for the recovery of costs associated with the Maritime Link in 2021. This is subject to a holdback of up to $10 million that is dependent upon the timing of commencement of the NS Block and NSPML has deferred collection of $23 million in depreciation expense. Approximately $162 million is included in NSPI rates.

Three of four generators at Muskrat Falls are completed and available for service, the first in Q3 2020, the second in Q2 2021 and the third in Q3 2021. Nalcor continues to advance towards construction completion of the Lower Churchill projects (including Muskrat Falls and LIL) with final commissioning targeted for Q1 2022. Nalcor commenced delivery of the NS Block on August 15, 2021 and the NS Block will be delivered over the next 35 years pursuant to the agreements. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related interruptions in supply with any resultant delivery shortfalls being delivered at a later date. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML’s 2022 assessment. A decision by the UARB is expected in early 2022.

In 2021, NSPML expects to invest approximately $10 million (2020 - $7 million) in capital.

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and Nalcor is targeting final commissioning for Q1 2022.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera’s current equity investment is $668 million, comprised of $410 million in equity contribution and $258 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 the Lower Churchill projects 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.

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 was included in the Other Electric Utilities segment in Q1 2020.

Removing the Q1 2020 earnings contribution from Emera Maine and the Q1 2020 recognition of a $10 million previously deferred corporate income tax recovery, Other Electric Utilities' earnings in 2021 are expected to increase over the prior year.

BLPC currently operates pursuant to a franchise to generate, transmit and distribute electricity on the island of Barbados 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. In March 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The new licenses are expected to take effect in 2021 on completion of the legislative process and will have terms ranging from 5 to 30 years. BLPC anticipates that any increased costs associated with the implementation of the new multi-licensed structure will be recoverable through BLPC's regulatory framework. BLPC is currently assessing the full impact of the new licenses on its business and working towards the successful implementation of the licenses.

On October 4, 2021 BLPC submitted a general rate review application to the FTC. The application seeks a rate adjustment and the implementation of a cost reflective rate structure that will facilitate the changes expected in the newly reformed electricity market and the country's transition towards 100 per cent renewable energy generation. The application seeks recovery of capital investment in plant, equipment and related infrastructure and results in an increase in annual non-fuel revenue of approximately $23 million USD to be effective April 2022. The application includes a request for an allowed regulatory ROE of 12.50 per cent on an allowed equity capital structure of 65 per cent. A decision is expected from the FTC by Q2 2022.

On September 23, 2021, GBPC filed an application for rate review with the GBPA. The application seeks a revision in base rates, charges and tariff classifications effective January 1, 2022 for a three-year period ending December 31, 2024. GBPC's proposed rates would reinstate the amortization of regulatory assets which had been deferred as part of the five-year rate stabilization plan. Rates were designed based on an 8.5 per cent to 9.0 per cent allowable regulated return on rate base and a target regulatory ROE of 12.84 per cent. A decision is expected from the GBPA by the end of 2021.

In 2021, capital investment in the Other Electric Utilities segment is expected to be approximately $85 million USD (2020 – $111 million USD including $14 million USD invested in Emera Maine projects), primarily in more efficient and cleaner sources of generation. BLPC expects to complete installation of a 33 MW diesel engine plant in January 2022. 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.

Gas Utilities and Infrastructure earnings are anticipated to be higher in 2021 than 2020 primarily due to approved base rate increases for PGS and NMGC.

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. PGS sales volumes are expected to increase above customer growth, as the COVID-19 pandemic impact on 2021 commercial energy sales is less than in 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.

NMGC's application for new rates was approved in December 2020 and took effect in January 2021. The new rates result in an increase in revenue of approximately $5 million USD annually. 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.

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause. On April 16, 2021, NMGC filed a Motion for Extraordinary Relief, as permitted by the NMPRC rules, to extend the terms of the repayment of the incremental gas costs and to recover a carrying charge. On June 15, 2021 the NMPRC approved the recovery of $108 million USD and related borrowing costs over a period of 30 months beginning July 1, 2021.

In 2021, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $430 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 2021 and will continue to invest in system improvements.

Other

The Other segment includes 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 the Other segment include Emera Energy and Emera Technologies LLC ("ETL"). Emera Energy consists of 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. ETL is a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers.

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 natural gas and electricity 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 expects 2021 annual adjusted net earnings to be within its guidance range of $15 to $30 million USD ($45 to $70 million USD of margin).

Absent the gain on the TECO Guatemala Holdings award in Q4 2020, the adjusted net loss from the Other segment is expected to be lower in 2021, primarily due to higher adjusted earnings from EES, decreased interest expense, lower OM&G and realized foreign exchange gains on cash flow hedges. The decrease is expected to be partially offset by increased taxes due to a lower net loss and increased project spend in ETL.

In 2021, capital investment in the Other segment is expected to be approximately $5 million (2020 - $3 million).

CONSOLIDATED BALANCE SHEET HIGHLIGHTS

Significant changes in the Condensed Consolidated Balance Sheets between December 31, 2020 and September 30, 2021 include:

millions of Canadian dollars		Increase (Decrease)	Explanation
Assets			
Cash and cash equivalents	**$**	**220**	Increased due to cash from operations, net issuances of debt at TEC and NMGC, and the issuance of preferred and common stock. This was partially offset by additions of property, plant and equipment at the regulated utilities and dividends on common stock.
Inventory		**78**	Increased due to higher commodity prices at Emera Energy, and higher materials inventory and fuel inventory costs at NSPI.
Derivative instruments (current and long-term)		**241**	Increased due to higher commodity prices, partially offset by settlements of derivative instruments at NSPI.
Regulatory assets (current and long-term)		**192**	Increased due to the NMGC winter event gas cost recovery, increased deferrals related to the FAM at NSPI, increased deferred income tax regulatory asset at NSPI and increased cost recovery clauses at Tampa Electric. This increase was partially offset by deferrals related to derivative instruments at NSPI.
Receivables and other assets (current and long-term)		**137**	Increased due to higher cash collateral and trade receivables at Emera Energy due to higher commodity prices, and increased fuel clause revenues at Tampa Electric due to higher natural gas prices. This increase was partially offset by lower gas transportation assets at Emera Energy, decreased cash collateral position on derivative instruments at NSPI, and seasonality of the business at NSPI and NMGC.
Property, plant and equipment, net of accumulated depreciation and amortization		**956**	Increased due to capital additions at Tampa Electric, PGS and NSPI.
Liabilities and Equity			
Short-term debt and long-term debt (including current portion)	**$**	**440**	Increased due to net issuances of long-term debt at TEC and NMGC. This increase was partially offset by repayment of short-term debt at TEC and net repayments on committed credit facilities at NSPI.
Accounts payable		**290**	Increased due to increased cash collateral positions on derivative instruments at NSPI and increased commodity prices at Emera Energy. This increase was partially offset by timing of payments at Tampa Electric and NMGC.
Derivative instruments (current and long-term)		**376**	Increased due to new contracts in 2021 and changes in existing positions, partially offset by reversal of 2020 contracts at Emera Energy.
Regulatory liabilities (current and long-term)		**151**	Increased due to deferrals related to derivative instruments at NSPI. This increase was partially offset by cost of removal at NSPI and Tampa Electric and decreased deferrals related to the FAM at NSPI.
Pension and post-retirement liabilities		**(56)**	Decreased due to cash contributions and lower net current benefit accrual at NSPI and Tampa Electric.
Other liabilities (current and long-term)		**110**	Increased due to higher accrued interest on long-term debt at Tampa Electric and Corporate and investment tax credits related to solar projects at Tampa Electric.
Common stock		**398**	Increased due to shares issued under Emera's at-the-market equity program and the dividend reinvestment plan.
Cumulative preferred stock		**418**	Increased due to issuances of preferred shares.
Retained earnings		**(298)**	Decreased due to dividends paid in excess of net income.

DEVELOPMENTS

Increase in Common Dividends

On September 24, 2021, the Emera Board of Directors approved an increase in the annual common share dividend rate to $2.65 from $2.55. The first payment will be effective November 15, 2021. Emera also extended its dividend growth rate target of four to five per cent through 2024.

Tampa Electric Rate Case Settlement Agreement

On August 6, 2021, Tampa Electric filed with the FPSC a joint motion for approval of a Settlement Agreement by Tampa Electric and the intervenors in relation to its rate case filed with the FPSC in April 2021. The Settlement Agreement provides for a projected increase of $191 million USD in rates annually, effective with January 2022 bills. This increase will consist of $123 million USD in base rate charges and $68 million USD to recover the costs of retiring assets including Big Bend coal generation assets Units 1 through 3 and meter assets. The Settlement Agreement further includes two subsequent year adjustments of $90 million USD and $21 million USD, effective January 2023 and January 2024, respectively related to the recovery of future investments in the Big Bend Modernization project and solar generation. The allowed equity in the capital structure will continue to be 54 per cent from investor sources of capital. The Settlement Agreement includes an allowed regulated ROE range of 9.0 per cent to 11.0 per cent with a 9.95 per cent midpoint. On October 21, 2021, the FPSC approved the settlement agreement and the final order, reflecting such approval, is expected to be issued in November 2021. For further information on the Settlement Agreement, refer to the “Business Overview and Outlook – Florida Electric Utility” section.

Delivery of NS Block

Nalcor commenced delivery of the NS Block on August 15, 2021 which will be delivered over the next 35 years pursuant to the agreements. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related interruptions in supply with any resultant delivery shortfalls being delivered at a later date**.** On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML’s 2022 assessments. A decision by the UARB is expected in early 2022. For further information on the NS Block, refer to the “Business Overview and Outlook – Canadian Electric Utilities” and “Contractual Obligations” sections.

Preferred Shares

On September 24, 2021, Emera issued 9 million Cumulative Redeemable First Preferred Shares, Series L at $25.00 per share at an annual yield of 4.60 per cent. The aggregate gross and net proceeds from the offering were $225 million and $222 million, respectively. The net proceeds of the preferred share offering will be used for general corporate purposes.

On April 6, 2021, Emera issued 8 million Cumulative Minimum Rate Reset First Preferred Shares, Series J at $25.00 per share at an initial dividend rate of 4.25 per cent. The aggregate gross and net proceeds from the offering were $200 million and $196 million, respectively. The net proceeds of the preferred share offering were used for general corporate purposes.

Appointments

Board of Directors

Effective August 10, 2021, Gil C. Quiniones joined the Emera Board of Directors. Mr. Quiniones is the former President and Chief Executive Officer of the New York Power Authority. Effective October 13, 2021, Mr. Quiniones resigned from the Emera Board of Directors following an appointment to a new senior executive position at a different organization.

Executive

On September 14, 2021, Emera announced that Helen Wesley was appointed President of PGS effective December 1, 2021. Ms. Wesley was most recently the Chief Operating Officer at PGS and will succeed T.J. Szelistowski who is retiring in December 2021.

OUTSTANDING STOCK DATA

Common stock

Issued and outstanding:	millions of shares		millions of Canadian dollars
Balance, December 31, 2019	242.48	$	6,216
Issuance of common stock (1)	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
Issuance of common stock (2)	3.74		211
Issued for cash under Purchase Plans at market rate	3.25		177
Discount on shares purchased under Dividend Reinvestment Plan	-		(3)
Options exercised under senior management stock option plan	0.22		10
Employee Share Purchase Plan	-		3
Balance, September 30, 2021	**258.64**	**$**	**7,103**

(1) In 2020, 4,544,025 common shares were issued under Emera's at-the-market program ("ATM program") at an average price of $56.04 per share for gross proceeds of $255 million ($251 million net of issuance costs).

(2) In Q3 2021, 1,402,797 common shares were issued under Emera's ATM program at an average price of $59.03 per share for gross proceeds of $83 million ($82 million net of after-tax issuance costs). For the nine months ended September 30, 2021, 3,739,823 common shares were issued under Emera's ATM program at an average price of $56.88 per share for gross proceeds of $213 million ($211 million net of after-tax issuance costs). As at September 30, 2021, an aggregate gross sales limit of $531 million remained available for issuance under the ATM program. Emera's ATM program was renewed on August 12, 2021. Refer to below for more information.

As at November 5, 2021, the amount of issued and outstanding common shares was 258.7 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 September 30, 2021 was 258.5 million (2020 – 248.4 million) and for the nine months ended September 30, 2021 was 256.0 million (2020 – 246.6 million).

ATM Equity Program

On August 12, 2021, Emera renewed its ATM Program that allows the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was renewed pursuant to a prospectus supplement to the Company's short form base shelf prospectus dated August 5, 2021. The ATM program is expected to remain in effect until September 5, 2023.

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 September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Operating revenues – regulated electric	**$ 634**	$ 506	**$ 1,613**	$ 1,381
Regulated fuel for generation and purchased power	**$ 217**	$ 102	**$ 501**	$ 301
Contribution to consolidated net income	**$ 135**	$ 131	**$ 302**	$ 296
Contribution to consolidated net income – CAD	**$ 169**	$ 175	**$ 377**	$ 400
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.65**	$ 0.70	**$ 1.47**	$ 1.62
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.26**	$ 1.33	**$ 1.25**	$ 1.35
EBITDA	**$ 278**	$ 270	**$ 715**	$ 690
EBITDA – CAD	**$ 349**	$ 359	**$ 893**	$ 933

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2020	**$ 131**	**$ 296**
Increased operating revenues - see Operating Revenues - Regulated Electric below	128	232
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below	(115)	(200)
Increased depreciation and amortization due to increased property, plant and equipment and a 2020 regulatory settlement	(9)	(28)
Increased AFUDC earnings due to the Big Bend Power Station modernization and solar projects	4	11
Other	(4)	(9)
Contribution to consolidated net income – 2021	**$ 135**	**$ 302**

Florida Electric Utility's CAD contribution to consolidated net income decreased $6 million to $169 million in Q3 2021, compared to $175 million in Q3 2020. Year-to-date in 2021, the CAD contribution to consolidated net income decreased $23 million to $377 million compared to $400 million for the same period in 2020. Decreases in both periods were due to the impact of the strengthening CAD. Excluding the impact of foreign exchange, higher AFUDC earnings increased contribution in both periods, partially offset by higher depreciation and amortization expense reflecting increased capital investment and a 2020 regulatory settlement.

The impact of the strengthening Canadian dollar decreased CAD earnings for the three and nine months ended September 30, 2021 by $10 million and $31 million, respectively.

Operating Revenues – Regulated Electric

Electric revenues increased $128 million to $634 million in Q3 2021, compared to $506 million in Q3 2020. Year-to-date in 2021, electric revenues increased $232 million to $1,613 million, compared to $1,381 million for the same period in 2020. Increases in both periods were due to higher fuel recovery clause revenue as a result of higher fuel costs.

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

Q3 Electric Revenues
millions of US dollars

	2021	2020
Residential	**$ 359**	$ 303
Commercial	**169**	128
Industrial	**45**	30
Other (1)	**61**	45
Total	**$ 634**	$ 506

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

YTD Electric Revenues
millions of US dollars

	2021	2020
Residential	**$ 867**	$ 762
Commercial	**439**	374
Industrial	**124**	99
Other (1)	**183**	146
Total	**$ 1,613**	$ 1,381

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

Q3 Electric Sales Volumes (1)
Gigawatt hours ("GWh")

	2021	2020
Residential	**3,104**	3,259
Commercial	**1,769**	1,728
Industrial	**570**	482
Other	**560**	527
Total	**6,003**	5,996

(1) Electric sales volumes are calculated based on billed hours only. GWh related to unbilled revenues are excluded.

YTD Electric Sales Volumes (1)
GWh

	2021	2020
Residential	**7,629**	7,657
Commercial	**4,619**	4,532
Industrial	**1,585**	1,431
Other	**1,499**	1,443
Total	**15,332**	15,063

(1) Electric sales volumes are calculated based on billed hours only. GWh related to unbilled revenues are excluded.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $115 million to $217 million in Q3 2021, compared to $102 million in Q3 2020 and year-to-date 2021, increased $200 million to $501 million in 2021, compared to $301 million in the same period in 2020. The increases in both periods were primarily due to increased natural gas prices.

Q3 Production Volumes
GWh

	2021	2020
Natural gas	**4,530**	4,652
Purchased power	**889**	910
Coal	**521**	301
Solar	**316**	304
Total	**6,256**	6,167

YTD Production Volumes
GWh

	2021	2020
Natural gas	**12,012**	12,907
Purchased power	**1,924**	1,766
Coal	**1,278**	560
Solar	**997**	888
Total	**16,211**	16,121

Q3 Average Fuel Costs

US dollars	2021	2020
Dollars per Megawatt hour ("MWh")	**$ 35**	$ 17

YTD Average Fuel Costs

US dollars	2021	2020
Dollars per MWh	**$ 31**	$ 19

Average fuel cost per MWh increased in Q3 2021 and year-to-date 2021, compared to the same periods in 2020, primarily due to increased natural gas prices.

Canadian Electric Utilities

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30 **2021**		2020		Nine months ended September 30 **2021**		2020
Operating revenues – regulated electric	**$**	**328**	$	324	**$**	**1,112**	$	1,117
Regulated fuel for generation and purchased power (1)	**$**	**169**	$	162	**$**	**554**	$	502
Income from equity investments	**$**	**25**	$	24	**$**	**78**	$	75
Contribution to consolidated net income	**$**	**42**	$	35	**$**	**174**	$	164
Contribution to consolidated earnings per common share – basic	**$**	**0.16**	$	0.14	**$**	**0.68**	$	0.67
EBITDA	**$**	**130**	$	130	**$**	**461**	$	457

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

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

For the millions of Canadian dollars		Three months ended September 30 **2021**		2020		Nine months ended September 30 **2021**		2020
NSPI	**$**	**18**	$	11	**$**	**98**	$	89
Equity investment in NSPML		**12**		11		**39**		38
Equity investment in LIL		**12**		13		**37**		37
Contribution to consolidated net income	**$**	**42**	$	35	**$**	**174**	$	164

Net Income

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

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
Contribution to consolidated net income – 2020	**$**	**35**	**$**	**164**
Increased (decreased) operating revenues - see Operating Revenues – Regulated Electric below		4		(5)
Increased fuel for generation and purchased power - see Regulated Fuel for Generation and Purchased Power below		(7)		(52)
Decreased FAM and fixed cost deferrals due to under-recovery of current period fuel costs compared to prior year's over-recovery of fuel costs, partially offset by the refund to customers in 2020 of prior years' fuel costs		6		61
Increased OM&G expense primarily due to higher costs for power generation and higher demand side management ("DSM") program costs		(6)		(7)
Decreased interest expense, net due to lower interest on the FAM regulatory deferral		4		6
Decreased income tax expense primarily due to increased tax deductions in excess of accounting depreciation related to property, plant and equipment		6		9
Other		-		(2)
Contribution to consolidated net income – 2021	**$**	**42**	**$**	**174**

Canadian Electric Utilities’ contribution to consolidated net income increased $7 million to $42 million in Q3 2021, compared to $35 million in Q3 2020 and year-to-date 2021 increased $10 million to $174 million compared to $164 million in 2020. Increases in both periods were primarily driven by higher contribution from NSPI. This was a result of lower income tax expense and lower interest on the FAM regulatory deferral, partially offset by lower Maritime Link assessment included in revenue compared to 2020 and higher OM&G expense.

NSPI

Operating Revenues – Regulated Electric

Operating revenues increased $4 million to $328 million in Q3 2021, compared to $324 million in Q3 2020 due to increased customer sales volumes, fuel-related pricing, and other revenue, partially offset by lower Maritime Link assessment included in revenue compared to 2020.

Year-to-date 2021, operating revenues decreased $5 million to $1,112 million compared to $1,117 million for the same period in 2020 due to lower Maritime Link assessment included in revenue and weather driven impacts on sales volumes, partially offset by increased customer sales volume growth, fuel-relating pricing and other revenue.

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

Q3 Electric Revenues
millions of Canadian dollars

		2021		2020
Residential	$	**154**	$	161
Commercial		**97**		93
Industrial		**61**		57
Other		**7**		7
Total	$	**319**	$	318

YTD Electric Revenues
millions of Canadian dollars

		2021		2020
Residential	$	**588**	$	607
Commercial		**303**		303
Industrial		**176**		164
Other		**21**		24
Total	$	**1,088**	$	1,098

Q3 Electric Sales Volumes
GWh

	2021	2020
Residential	**873**	898
Commercial	**700**	657
Industrial	**653**	614
Other	**37**	37
Total	**2,263**	2,206

YTD Electric Sales Volumes
GWh

	2021	2020
Residential	**3,432**	3,493
Commercial	**2,172**	2,138
Industrial	**1,851**	1,712
Other	**115**	149
Total	**7,570**	7,492

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $7 million to $169 million in Q3 2021, compared to $162 million in Q3 2020, and year-to-date 2021 increased $52 million to $554 million, compared to $502 million in the same period in 2020. Increases in both periods were due to changes in generation mix driven by emissions constraints. Year-over-year, higher commodity prices and higher Maritime Link assessment costs also contributed to the increase.

Q3 Production Volumes
GWh

	2021	2020
Coal	**978**	949
Natural gas	**491**	495
Purchased power – other	**277**	114
Petcoke	**105**	245
Oil	**10**	2
Total non-renewables	**1,861**	1,805
Purchased power	**377**	362
Wind and hydro	**124**	126
Biomass	**40**	44
Total renewables	**541**	532
Total production volumes	**2,402**	2,337

YTD Production Volumes
GWh

	2021	2020
Coal	**3,399**	3,093
Natural gas	**1,302**	1,521
Purchased power – other	**669**	428
Petcoke	**311**	779
Oil	**67**	14
Total non-renewables	**5,748**	5,835
Purchased power	**1,441**	1,299
Wind and hydro	**764**	786
Biomass	**109**	85
Total renewables	**2,314**	2,170
Total production volumes	**8,062**	8,005

Q3 Average Fuel Costs

		2021	2020
Dollars per MWh	**$**	**70** $	69

YTD Average Fuel Costs

		2021	2020
Dollars per MWh	**$**	**69** $	63

Average fuel cost per MWh increased in Q3 2021 and year-to-date 2021, compared to the same periods in 2020. This was primarily due to changes in generation mix driven by emissions constraints, with increased generation from lower carbon intensity sources such as IPPs, import, and biomass generation and decreased generation from solid fuel, and natural gas. Increased commodity prices and higher Maritime Link assessment costs contributed to a higher average fuel cost year-over-year.

NSPI's FAM regulatory balance increased $71 million from a regulatory liability of $21 million at December 31, 2020 to a regulatory asset of $50 million at September 30, 2021 primarily due to under-recovery of current period fuel costs.

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" section.

For the millions of US dollars (except per share amounts)		Three months ended September 30 **2021**		2020		Nine months ended September 30 **2021**		2020
Operating revenues – regulated electric	**$**	**96**	$	79	**$**	**257**	$	275
Regulated fuel for generation and purchased power (1)	**$**	**46**	$	33	**$**	**123**	$	110
Adjusted contribution to consolidated net income	**$**	**6**	$	5	**$**	**12**	$	19
Adjusted contribution to consolidated net income – CAD	**$**	**8**	$	6	**$**	**15**	$	25
After-tax equity securities MTM loss	**$**	**-**	$	-	**$**	**(1)**	$	-
Contribution to consolidated net income	**$**	**6**	$	5	**$**	**11**	$	19
Contribution to consolidated net income – CAD	**$**	**8**	$	6	**$**	**14**	$	25
Adjusted contribution to consolidated earnings per common share – basic – CAD	**$**	**0.03**	$	0.02	**$**	**0.06**	$	0.10
Contribution to consolidated earnings per common share – basic – CAD	**$**	**0.03**	$	0.02	**$**	**0.05**	$	0.10
Net income weighted average foreign exchange rate – CAD/USD	**$**	**1.26**	$	1.33	**$**	**1.26**	$	1.36
Adjusted EBITDA	**$**	**22**	$	21	**$**	**61**	$	77
Adjusted EBITDA – CAD	**$**	**28**	$	26	**$**	**77**	$	102

(1) Regulated fuel for generation and purchased power includes transmission pool expense in year-to-date 2020 related to Emera Maine

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

For the millions of US dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
BLPC	**$ 3**	$ 2	**$ 5**	$ 15
GBPC	**3**	1	**8**	2
Emera Maine	**-**	-	**-**	4
Other	**-**	2	**(1)**	(2)
Adjusted contribution to consolidated net income	**$ 6**	$ 5	**$ 12**	$ 19

Excluding the change in MTM, Other Electric Utilities CAD contribution to consolidated net income in Q3 2021 increased $2 million to $8 million, compared to $6 million in Q3 2020 due to higher other income at GBPC. Year-to-date 2021, the CAD contribution decreased $10 million to $15 million, compared to $25 million, for the same period in 2020. This was primarily due to the sale of Emera Maine in Q1 2020 and the recognition of a deferred corporate income tax recovery at BLPC in Q1 2020 related to the enactment of a lower corporate income tax rate in December 2018. These decreases were partially offset by higher other income at GBPC, and lower interest costs.

The foreign exchange rate had minimal impact for the three months ended September 30, 2021. Year-to-date 2021, the strengthening of the CAD decreased earnings and adjusted earnings by $1 million.

Operating Revenues – Regulated Electric

Operating revenues increased $17 million to $96 million in Q3 2021, compared to $79 million in Q3 2020 due to increased fuel revenue at BLPC as a result of higher oil prices. Year-to-date in 2021, revenues decreased $18 million to $257 million compared to $275 million in the same period in 2020. The decrease year-over-year was a result of the sale of Emera Maine, partially offset by higher fuel revenue at BLPC due to higher fuel prices.

Electric sales volumes were higher in Q3 2021 with 336 GWh compared to 326 GWh in Q3 2020. Year-to-date, electric sales volumes were higher in 2021 with 932 GWh compared to 927 GWh for the same period in 2020.

Regulated Fuel for Generation and Purchased Power

Regulated fuel for generation and purchased power increased $13 million to $46 million in Q3 2021, compared to $33 million in Q3 2020. Year-to-date in 2021, regulated fuel for generation and purchased power increased $13 million to $123 million, compared to $110 million in 2020. The increases in both periods were due to higher fuel prices at BLPC. Year-over-year the increase was partially offset by transmission pool expense at Emera Maine in 2020.

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 September 30 2021	 2020	Nine months ended September 30 2021	 2020
Operating revenues – regulated gas (1)	**$ 189**	$ 146	**$ 699**	$ 546
Operating revenues – non-regulated	**3**	3	**10**	9
Total operating revenue	**$ 192**	$ 149	**$ 709**	$ 555
Regulated cost of natural gas	**$ 57**	$ 30	**$ 236**	$ 141
Income from equity investments	**$ 4**	$ 3	**$ 12**	$ 10
Contribution to consolidated net income	**$ 22**	$ 16	**$ 113**	$ 87
Contribution to consolidated net income – CAD	**$ 29**	$ 20	**$ 143**	$ 117
Contribution to consolidated earnings per common share – basic – CAD	**$ 0.11**	$ 0.08	**$ 0.56**	$ 0.47
Net income weighted average foreign exchange rate – CAD/USD	**$ 1.26**	$ 1.32	**$ 1.26**	$ 1.35
EBITDA	**$ 66**	$ 52	**$ 258**	$ 213
EBITDA – CAD	**$ 83**	$ 69	**$ 324**	$ 288

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2020 - $12 million) for the three months ended September 30, 2021 and $34 million (2020 - $34 million) for the nine months ended September 30, 2021; however, it is excluded from the gas revenues analysis below.

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

For the millions of US dollars	Three months ended September 30 2021	 2020	Nine months ended September 30 2021	 2020
PGS	**$ 14**	$ 10	**$ 60**	$ 39
NMGC	**(4)**	(5)	**18**	18
Other	**12**	11	**35**	30
Contribution to consolidated net income	**$ 22**	$ 16	**$ 113**	$ 87

Net Income

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

For the millions of US dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income – 2020	**$ 16**	**$ 87**
Increased gas operating revenues - see Operating Revenues - Regulated Gas below	43	153
Increased cost of natural gas sold - See Regulated Cost of Natural Gas below	(27)	(95)
Increased depreciation and amortization expense due to increased property, plant and equipment	(4)	(11)
Increased OM&G expense primarily due to higher labour and insurance costs at PGS and NMGC	(4)	(12)
Other	(2)	(9)
Contribution to consolidated net income – 2021	**$ 22**	**$ 113**

Gas Utilities and Infrastructure's CAD contribution to consolidated net income increased $9 million to $29 million in Q3 2021, compared to $20 million in Q3 2020 and year-to-date 2021 increased $26 million to $143 million, compared to $117 million in 2020. The increases in both periods were due to higher base revenues at PGS as the result of a base rate increase effective January 1, 2021 and customer growth.

The impact of the change in the foreign exchange rate decreased CAD earnings for the three months ended September 30, 2021 and year-to-date 2021 by $1 million and $9 million respectively.

Operating Revenues – Regulated Gas

Gas Utilities and Infrastructure's operating revenues increased $43 million to $189 million in Q3 2021, compared to $146 million in Q3 2020 and year-to-date 2021 increased $153 million to $699 million, compared to $546 million in the same period in 2020. The increases in both periods were due to a base rate increase at PGS and NMGC effective January 1, 2021, customer growth at PGS, and higher purchased gas adjustment clause revenues at PGS and NMGC as a result of higher gas prices.

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

Q3 Gas Revenues
millions of US dollars

	2021	2020
Residential	$ 81	$ 57
Commercial	61	40
Industrial (1)	13	10
Other (2)	23	27
Total (3)	$ 178	$ 134

(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 (2020 – $12 million).

YTD Gas Revenues
millions of US dollars

	2021	2020
Residential	$ 343	$ 250
Commercial	214	144
Industrial (1)	38	30
Other (2)	70	88
Total (3)	$ 665	$ 512

(1) Industrial includes sales to power generation customers.
(2) Other includes off-system sales to other utilities and various other items.
(3) Excludes $34 million of finance income from Brunswick Pipeline (2020 – $34 million).

Q3 Gas Volumes
Therms (millions)

	2021	2020
Residential	38	38
Commercial	164	150
Industrial	384	417
Other	23	68
Total	609	673

YTD Gas Volumes
Therms (millions)

	2021	2020
Residential	285	273
Commercial	587	547
Industrial	1,107	1,198
Other	110	239
Total	2,089	2,257

Regulated Cost of Natural Gas

Regulated cost of natural gas increased $27 million to $57 million in Q3 2021, compared to $30 million in Q3 2020 and year-to-date 2021 increased $95 million to $236 million in Q3 2021, compared to $141 million in the same period in 2020. The increases in both periods were due to higher gas prices at PGS and NMGC.

Gas sales by type are summarized in the following table:

Q3 Gas Volumes by Type
Therms (millions)

	2021	2020
System supply	78	92
Transportation	531	581
Total	609	673

YTD Gas Volumes by Type
Therms (millions)

	2021	2020
System supply	444	493
Transportation	1,645	1,764
Total	2,089	2,257

Other

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30 **2021**		2020		Nine months ended September 30 **2021**		2020
Marketing and trading margin (1) (2)	**$**	**(4)**	$	(12)	**$**	**63**	$	16
Other non-regulated operating revenue		**8**		10		**25**		25
Total operating revenues – non-regulated	**$**	**4**	$	(2)	**$**	**88**	$	41
Income from equity investments	**$**	**1**	$	-	**$**	**12**	$	17
Adjusted contribution to consolidated net income (loss)	**$**	**(73)**	$	(70)	**$**	**(154)**	$	(229)
Gain on sale, net of tax and transaction costs		**-**		-		**-**		309
Impairment charges, net of tax		**-**		-		**-**		(26)
After-tax derivative MTM loss		**(245)**		(82)		**(368)**		(95)
Contribution to consolidated net income (loss)	**$**	**(318)**	$	(152)	**$**	**(522)**	$	(41)
Adjusted contribution to consolidated earnings per common share – basic	**$**	**(0.28)**	$	(0.28)	**$**	**(0.60)**	$	(0.93)
Contribution to consolidated earnings per common share – basic	**$**	**(1.23)**	$	(0.61)	**$**	**(2.04)**	$	(0.17)
Adjusted EBITDA	**$**	**(13)**	$	(22)	**$**	**41**	$	(25)

(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 loss of $334 million in Q3 2021 (2020 - $131 million loss) and a loss of $501 million year-to-date (2020 – $155 million loss).

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

For the millions of Canadian dollars		Three months ended September 30 **2021**		2020		Nine months ended September 30 **2021**		2020
Emera Energy	**$**	**(5)**	$	(12)	**$**	**37**	$	2
Corporate – see breakdown of adjusted contribution below		**(59)**		(54)		**(174)**		(223)
Emera Technologies		**(7)**		(3)		**(13)**		(7)
Other		**(2)**		(1)		**(4)**		(1)
Adjusted contribution to consolidated net income (loss)	**$**	**(73)**	$	(70)	**$**	**(154)**	$	(229)

Net Income

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

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
Contribution to consolidated net income (loss) – 2020	**$ (152)**	**$ (41)**
Increased marketing and trading margin - see Emera Energy	8	47
Decreased interest expense in both periods due to the impact of a stronger CAD and lower interest rates. Year-over-year also decreased due to the repayment of corporate debt	7	29
Realized gain on hedges entered into to hedge foreign exchange earnings exposure	4	17
Revaluation of net deferred income tax assets and liabilities resulting from the enactment of a lower Nova Scotia provincial corporate income tax rate in Q1 2020, including $2 million recovery related to MTM	-	11
Increased preferred stock dividends quarter-over-quarter primarily due to timing of dividend declaration. In addition, increased preferred stock dividends in both periods due to the issuance of preferred shares	(14)	(2)
Decreased income tax recovery primarily due to decreased losses before provision for income taxes	(4)	(32)
Increased MTM loss, net of tax, quarter-over-quarter, primarily due to higher forward pricing for New England gas compared to transport hedges in place at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges. This is partially offset by a larger reversal of MTM losses in Q3 2021 at Emera Energy. Increased MTM loss, net of tax, year-over-year due to higher forward pricing for New England gas compared to transport hedges in place at Emera Energy and the reversal of 2020 foreign exchange gains on cash flow hedges, partially offset by lower amortization of gas transportation assets in 2021	(163)	(271)
2020 gain on sale and impairment charges, net of tax	-	(283)
Other	(4)	3
Contribution to consolidated net income (loss) – 2021	**$ (318)**	**$ (522)**

Emera Energy

Marketing and trading margin increased $8 million to a loss of $4 million in Q3 2021, compared to a loss of $12 million for the same period in 2020 due to more favourable market conditions, specifically higher natural gas prices in Q3 2021 compared to Q3 2020.

Year-to-date in 2021 margin increased $47 million to $63 million in 2021, compared to $16 million for the same period in 2020. This increase reflected the mid-February extreme weather event across the South-Central US which sharply increased pricing and volatility in adjacent markets where Emera Energy has a presence and as a result the business was able to capitalize. The Northeast, though seasonally cold, was largely insulated from the weather event, however still provided steady opportunity throughout Q1. In addition, Emera Energy benefited from more favourable market conditions compared to 2020, specifically the impact of weather in several key market areas, which resulted in higher market prices and volatility which led to natural gas margins.

Corporate

Corporate's adjusted loss is summarized in the following table:

For the millions of Canadian dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Operating expenses (1)	**$ 10**	$ 6	**$ 27**	$ 37
Interest expense	**65**	72	**199**	228
Income tax expense (recovery)	**(18)**	(19)	**(57)**	(78)
Preferred dividends	**14**	-	**36**	34
Income tax expense associated with the revaluation of Corporate deferred income tax assets and liabilities due to the 2020 reduction in the Nova Scotia provincial corporate income tax rate	**-**	-	**-**	9
Other (2)	**(12)**	(5)	**(31)**	(7)
Corporate adjusted net loss	**$ (59)**	$ (54)	**$ (174)**	$ (223)

(1) Operating expenses include OM&G and depreciation.
(2) Other includes realized foreign exchange gains on cash flow hedges to hedge foreign exchange earnings exposure, Q3 2021 includes a $4 million gain (2020- nil) and year-to-date gain of $13 million (2020 - $4 million loss).

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.

The ongoing COVID-19 pandemic, including government measures to address the 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. For further information on the potential future impacts of COVID on Emera and its businesses, refer to the “Business Overview and Outlook” and “Liquidity and Capital Resources” sections in the Company’s 2020 annual MD&A.

On a consolidated basis, COVID-19 has not had a material financial impact to net earnings to date in 2021 and is not expected to have a material financial impact in 2021. For further discussion, refer to the “Business Overview and Outlook – COVID-19 Pandemic” section. To date, there have been no significant customer defaults and as of September 30, 2021, 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 but is not expected to be material. The utilities are continuing to monitor customer accounts and are working with customers on payment arrangements.

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 investments 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 investment plan cannot be predicted at this time. 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 are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan and at-the-market program.

Emera has credit facilities with varying maturities that cumulatively provide $3.4 billion of credit, with approximately $1.6 billion undrawn and available at September 30, 2021. The Company was holding a cash balance of $476 million at September 30, 2021. For further discussion, refer to the "Debt Management" section below. Refer to notes 19 and 20 in the condensed consolidated interim financial statements for additional information regarding the credit facilities.

Consolidated Cash Flow Highlights

Significant changes in the Condensed Consolidated Statements of Cash Flows between the nine months ended September 30, 2021 and 2020 include:

millions of Canadian dollars	2021	2020	Change
Cash, cash equivalents, and restricted cash, beginning of period	**$ 254**	$ 274	$ (20)
Provided by (used in):			
Operating cash flow before change in working capital	**1,035**	1,101	(66)
Change in working capital	**71**	139	(68)
Operating activities	**$ 1,106**	$ 1,240	$ (134)
Investing activities	**(1,576)**	(536)	(1,040)
Financing activities	**693**	(595)	1,288
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(1)**	(48)	47
Cash, cash equivalents, and restricted cash, end of period	**$ 476**	$ 335	$ 141

Cash Flow from Operating Activities

Net cash provided by operating activities decreased $134 million to $1,106 million for the nine months ended September 30, 2021, compared to $1,240 million for the same period in 2020.

Cash from operations before changes in working capital decreased $66 million. The decrease was primarily due to the deferral of gas costs at NMGC resulting from the February 2021 extreme cold weather event, higher under-recovery of clause-related costs primarily due to higher natural gas prices at Tampa Electric and PGS and the sale of Emera Maine in Q1 2020. This was partially offset by increased marketing and trading margin at Emera Energy and higher base revenue at PGS.

Changes in working capital decreased operating cash flows by $68 million due to unfavourable changes in cash collateral positions at Emera Energy, unfavourable changes in accounts receivable at Tampa Electric, PGS and NMGC, increased fuel inventory at Emera Energy and NSPI, the receipt of a 2019 income tax refund at NSPI in 2020, and timing of accounts payable payments at NMGC and Tampa Electric. This was partially offset by favourable changes in cash collateral positions on derivative instruments at NSPI.

Cash Flow from Investing Activities

Net cash used in investing activities increased $1,040 million to $1,576 million for the nine months ended September 30, 2021, compared to $536 million for the same period in 2020. The increase was due to the proceeds of $1.4 billion received on the sale of Emera Maine in 2020, partially offset by lower capital expenditures in 2021.

Capital expenditures for the nine months ended September 30, 2021, including AFUDC, were $1,640 million compared to $1,967 million for the same period in 2020. Details of the 2021 capital spend by segment are shown below:

- $927 million - Florida Electric Utility (2020 – $1,029 million);
- $248 million - Canadian Electric Utilities (2020 – $253 million);
- $85 million - Other Electric Utilities (2020 – $124 million);
- $378 million - Gas Utilities and Infrastructure (2020 – $559 million); and
- $2 million - Other (2020 – $2 million).

Cash Flow from Financing Activities

Net cash provided by financing activities increased $1,288 million to $693 million for the nine months ended September 30, 2021, compared to cash used in financing activities of $595 million for the same period in 2020. The increase was due to net proceeds from the issuance of long-term debt at Tampa Electric, NMGC and PGS in 2021, repayment of long-term debt at TECO Finance in 2020, lower net repayments of committed credit facilities at TECO Finance and Emera and the issuance of preferred shares. This was partially offset by higher net repayments of short-term debt at TEC and net proceeds from long-term debt in 2020 at NSPI.

Contractual Obligations

As at September 30, 2021, 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	$ 125	$ 526	$ 553	$ 448	$ 477	$ 12,427	$ 14,556
Interest payment obligations (1)	239	607	587	575	555	7,085	9,648
Transportation (2)	185	485	406	348	311	2,806	4,541
Purchased power (3)	68	227	221	238	237	2,176	3,167
Fuel, gas supply and storage	303	340	72	45	40	24	824
Capital projects	473	159	95	6	1	-	734
Asset retirement obligations	9	2	7	2	2	391	413
Long-term service agreements (4)	36	64	68	48	32	90	338
Pension and post-retirement obligations (5)	8	38	32	33	32	192	335
Equity investment commitments (6)	-	240	-	-	-	-	240
Leases and other (7)	3	16	16	15	8	120	178
Demand side management	10	45	-	-	-	-	55
Long-term payable	1	5	5	-	-	-	11
	$ 1,460	$ 2,754	$ 2,062	$ 1,758	$ 1,695	$ 25,311	$ 35,040

(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 September 30, 2021, including any expected required payment under associated swap agreements.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $144 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.
(4) 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.
(5) 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.
(6) Emera has a commitment to make equity contributions to the LIL.
(7) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

Nalcor continues to advance towards construction completion of the Lower Churchill projects (including Muskrat Falls and LIL) with final commissioning targeted for Q1 2022. Three of four generators at Muskrat Falls are completed and available for service, the first in Q3 2020, the second in Q2 2021, and the third in Q3 2021.

The UARB approved assessment for 2021 is approximately $172 million. This is subject to a holdback of up to $10 million, that is dependent upon the timing of commencement of the NS Block and NSPML has deferred collection of $23 million in depreciation expense. Nalcor has commenced delivery of the NS Block on August 15, 2021 and the NS Block will be delivered over the next 35 years pursuant to the agreements with Nalcor. As Nalcor is in the final stages of commissioning the LIL, there will be periodic commissioning related interruptions in supply with any resultant delivery shortfalls being delivered at a later date. On August 9, 2021, NSPML filed a final capital cost application with the UARB seeking approval to recover capital costs associated with the Maritime Link and approval of NSPML’s 2022 assessment.

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 $164 million and $162 million for 2021 and 2022, respectively. 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 subject to UARB approval.

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, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets effective August 15, 2021, the date the NS Block commenced, and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Leases and other" in the above table.

Debt Management

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to approximately $3.4 billion committed syndicated bank lines of credit in either CAD or USD, per the table below.

millions of dollars	Maturity	Credit Facilities	Utilized	Undrawn and Available
Emera – Unsecured committed revolving credit facility	June 2026	$ 900	$ 327	$ 573
TEC (in USD) – Unsecured committed revolving credit facility (1)	March 2023	800	461	339
NSPI – Unsecured committed revolving credit facility	October 2024	600	198	402
Emera – Unsecured non-revolving facility	December 2021	400	400	-
TECO Finance (in USD) – Unsecured committed revolving credit facility	March 2023	400	265	135
NMGC (in USD) – Unsecured committed revolving credit facility	March 2023	125	14	111
NMGC (in USD) - Unsecured non-revolving facility	September 2022	100	100	-
Other (in USD) – Unsecured committed revolving credit facilities	Various	35	21	14

(1) This facility is available for use by Tampa Electric and PGS. At September 30, 2021, $346 million USD was used by Tampa Electric and $115 million USD was used by PGS.

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements as at September 30, 2021.

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

Florida Electric Utility

On May 25, 2021, TEC established a commercial paper program. Amounts available under the commercial paper program may be borrowed, repaid and reborrowed with the aggregate amount of the notes outstanding at any time not to exceed $800 million USD. The full amount of commercial paper issued is backed by TEC's credit facility and results in an equal amount of its credit facility being considered drawn and unavailable.

On May 15, 2021, TEC repaid its $278 million USD, 5.4 per cent notes upon maturity. The notes were repaid using existing credit facilities.

On March 18, 2021, TEC completed an issuance of $800 million USD senior notes. The issuance included $400 million USD senior notes that bear interest at a rate of 2.40 per cent with a maturity date of March 15, 2031 and $400 million USD senior notes that bear interest at a rate of 3.45 per cent with a maturity date of March 15, 2051.

As a result of the $800 million USD senior notes issuance discussed above, on March 23, 2021, TEC repaid its $300 million USD non-revolving term loan. TEC also repaid its $150 million USD accounts receivable collateralized borrowing facility and the agreement subsequently matured and terminated on March 22, 2021.

Gas Utilities and Infrastructure

On July 16, 2021, Brunswick Pipeline extended the maturity date of its $250 million credit facility from May 17, 2023 to June 30, 2025. There were no other significant changes in commercial terms from the prior agreement.

On March 25, 2021, NMGC entered into a $100 million USD unsecured, non-revolving credit facility with a maturity date of September 23, 2022. The credit facility contains customary representations and warranties, events of default, financial and other covenants and bears interest based on either the LIBOR, prime rate, or the federal funds rate, plus a margin. Proceeds from this issuance were used to pay for higher than normal gas costs as a result of the severe cold weather event in February 2021 (for more detail, refer to "Business Overview and Outlook – Gas Utilities and Infrastructure" section).

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, which was classified as long-term debt at December 31, 2020.

Other

On July 23, 2021, Emera extended the maturity date of its $900 million unsecured committed revolving credit facility from June 30, 2024 to June 30, 2026. There were no other significant changes in commercial terms from the prior agreement.

On June 4, 2021, Emera US Finance LP completed an issuance of $750 million USD senior notes. The issuance included $450 million USD senior notes that bear interest at a rate of 2.64 per cent with a maturity date of June 15, 2031 and $300 million USD senior notes that bear interest at a rate of 0.83 per cent with a maturity date of June 15, 2024. The USD senior notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary.

As a result of the $750 million USD senior notes issuance discussed above, on June 15, 2021, Emera US Finance LP repaid its previously outstanding $750 million USD senior notes on maturity.

Preferred Share Issuances

On September 24, 2021, Emera issued 9 million Cumulative Redeemable First Preferred Shares, Series L at $25.00 per share at an annual yield of 4.60 per cent. The aggregate gross and net proceeds from the offering were $225 million and $222 million, respectively.

On April 6, 2021, Emera issued 8 million Cumulative Minimum Rate Reset First Preferred Shares, Series J at $25.00 per share at an initial dividend rate of 4.25 per cent. The aggregate gross and net proceeds from the offering were $200 million and $196 million, respectively.

Guarantees and Letters of Credit

Emera’s guarantees and letters of credit are consistent with those disclosed in the Company’s 2020 annual MD&A, with updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of $62 million USD (December 31, 2020 - $55 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.

NSPI has issued guarantees in the amount of $28 million USD (December 31, 2020 - $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.

On October 28, 2021, NSPI issued an additional guarantee of $85 million USD on behalf of its subsidiary NSPEMI, relating to a 15-year natural gas transportation commitment.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy 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 Condensed Consolidated Statements of Income. NSPI’s expense is reported in Regulated fuel for generation and purchased power, totalling $27 million for the three months ended September 30, 2021 (2020 - $27 million) and $91 million for the nine months ended September 30, 2021 (2020 - $82 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 Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $4 million for the three months ended September 30, 2021 (2020 - $2 million) and $14 million for the nine months ended September 30, 2021 (2020 - $13 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera’s Condensed Consolidated Balance Sheets as at September 30, 2021 and at December 31, 2020.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

There have been no material changes in Emera's risk management profile and practices from those disclosed in the Company's 2020 annual MD&A.

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	**September 30 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ -**	$ 1
Net derivative instrument assets	**$ -**	$ 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	Three months ended September 30 **2021**	 2020	Nine months ended September 30 **2021**	 2020
Operating revenues – regulated	**$ -**	$ -	**$ -**	$ (2)
Interest expense, net	**1**	-	**1**	-
Effective net gains (losses)	**$ 1**	$ -	**$ 1**	$ (2)

The effective net gains (losses) reflected in the above table would be offset in net income by the hedged item realized in the period.

Regulatory Items Recognized on the Balance Sheets

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

As at millions of Canadian dollars	**September 30 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 261**	$ 14
Regulatory assets (current and other assets)	**24**	65
Derivative instrument liabilities (current and long-term liabilities)	**(25)**	(62)
Regulatory liabilities (current and long-term liabilities)	**(260)**	(15)
Net asset	**$ -**	$ 2

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Regulated fuel for generation and purchased power (1)	**$ 13**	$ (8)	**$ 9**	$ (18)
Net gains (losses)	**$ 13**	$ (8)	**$ 9**	$ (18)

(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	**September 30 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 65**	$ 68
Derivative instrument liabilities (current and long-term liabilities)	**(689)**	(275)
Net derivative instrument liability	**$ (624)**	$ (207)

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	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
Operating revenue - non-regulated	**$ (235)**	$ (187)	**$ (226)**	$ 35
Non-regulated fuel for purchased power	**-**	1	**1**	(3)
Net gains (losses)	**$ (235)**	$ (186)	**$ (225)**	$ 32

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	**September 30 2021**	December 31 2020
Derivative instrument assets (current and other assets)	**$ 13**	$ 15
Derivative instrument liabilities (current and long-term liabilities)	**-**	(1)
Net derivative instrument assets	**$ 13**	$ 14

Other Derivatives Recognized in Net Income

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

For the millions of Canadian dollars	Three months ended September 30 **2021**	2020	Nine months ended September 30 **2021**	2020
OM&G	**$ 3**	$ 4	**$ 9**	$ (3)
Other income, net	**(1)**	5	**2**	5
Total gains	**$ 2**	$ 9	**$ 11**	$ 2

DISCLOSURE AND INTERNAL CONTROLS

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. 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 of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design of the Company's DC&P and ICFR as at September 30, 2021, to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

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

There were no changes in the Company's ICFR during the quarter ended September 30, 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with 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.

Management has analyzed the impact of the COVID-19 pandemic on its estimates and assumptions and concluded that no material adjustments were required for the three and nine months ended September 30, 2021.

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. Actual results may differ significantly from these estimates.

Goodwill Impairment Assessments

Management considered whether the potential impacts of the COVID-19 pandemic on future earnings required testing for goodwill impairment in Q3 2021 and determined that it is more likely than not that the fair value of reporting units that include goodwill exceeded their respective carrying amounts as of September 30, 2021.

As of September 30, 2021, $5.7 billion of Emera's goodwill was related to TECO Energy (Tampa Electric, PGS and NMGC reporting units). Given the significant excess of fair value over carrying amounts calculated for these reporting units as of the last quantitative test performed in Q4 2019, and the results of the qualitative assessment performed in Q4 2020, management does not expect the COVID-19 pandemic to have an impact on the goodwill associated with these reporting units.

As of September 30, 2021, $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. As part of the assessment management considered potential impacts of the COVID-19 pandemic on the future earnings of the reporting unit. No adverse changes in significant assumptions were identified in Q3 2021 and no impairment has been recorded for the three and nine months ended September 30, 2021 associated with this goodwill. Adverse changes in significant assumptions could result in a future impairment.

Long-Lived Assets Impairment Assessments

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 September 30, 2021, there are no indications of impairment of Emera's long-lived assets. 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.

No impairment charges were recognized for the three and nine months ended September 30, 2021. Impairment charges of nil and $25 million ($26 million after tax) were recognized on certain assets for the three and nine months ended September 30, 2020, respectively.

Receivables and Allowance for Credit Losses

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. The economic impact of COVID-19, in the service territories where 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.

Pension and Other Post-Retirement Employee Benefits

The COVID-19 pandemic could impact key actuarial assumptions used to account for employee post-retirement benefits as a result of changes in the market. These changes could impact assumptions 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. Fluctuations in actual equity market returns and changes in interest rates as a result of the COVID-19 pandemic may also result in changes to pension costs and funding in future periods.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2021, are described as follows:

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity

The Company adopted Accounting Standard Update ("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) effective January 1, 2021 using the modified retrospective approach. 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. There was no material impact on the consolidated financial statements as a result of the adoption of this standard.

Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs that have been issued, but are not yet effective, are consistent with those disclosed in the Company's 2020 audited consolidated financial statements, with updates noted below.

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 and focusing the disclosure models, 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)	**Q3 2021**	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Operating revenues	**$ 1,148**	$ 1,137	$ 1,612	$ 1,537	$ 1,163	$ 1,169	$ 1,637	$ 1,616
Net income (loss) attributable to common shareholders	**(70)**	(17)	273	273	84	58	523	193
Adjusted net income attributable to common shareholders	**175**	137	243	188	166	118	193	145
Earnings (loss) per common share – basic	**(0.27)**	(0.07)	1.08	1.09	0.34	0.24	2.14	0.79
Earnings (loss) per common share – diluted	**(0.27)**	(0.07)	1.08	1.08	0.34	0.23	2.13	0.80
Adjusted earnings per common share – basic	**0.68**	0.54	0.96	0.75	0.67	0.48	0.79	0.60

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.