EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2018 and 2017

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Operating revenues				
Regulated electric	**$ 1,289**	$ 1,214	**$ 3,624**	$ 3,593
Regulated gas	**202**	187	**749**	727
Non-regulated	**4**	26	**352**	433
Total operating revenues (note 5)	**1,495**	1,427	**4,725**	4,753
Operating expenses				
Regulated fuel for generation and purchased power	**448**	409	**1,250**	1,225
Regulated cost of natural gas	**65**	71	**267**	272
Non-regulated fuel for generation and purchased power	**49**	40	**159**	149
Non-regulated direct costs	**2**	6	**5**	26
Operating, maintenance and general	**368**	322	**1,134**	1,014
Provincial, state and municipal taxes	**89**	82	**256**	247
Depreciation and amortization	**236**	207	**687**	644
Total operating expenses	**1,257**	1,137	**3,758**	3,577
Income from operations	**238**	290	**967**	1,176
Income from equity investments (note 6)	**41**	34	**121**	90
Other income (expenses), net	**5**	(10)	**(16)**	(21)
Interest expense, net	**176**	170	**527**	523
Income before provision for income taxes	**108**	144	**545**	722
Income tax expense (recovery) (note 7)	**(33)**	45	**29**	191
Net income	**141**	99	**516**	531
Non-controlling interest in subsidiaries	**1**	4	**1**	9
Preferred stock dividends	**22**	14	**36**	28
Net income attributable to common shareholders	**$ 118**	$ 81	**$ 479**	$ 494
Weighted average shares of common stock outstanding (in millions) (note 9)				
Basic	**233.7**	213.8	**232.4**	212.7
Diluted	**235.2**	215.3	**233.9**	214.1
Earnings per common share (note 9)				
Basic	**$ 0.51**	$ 0.38	**$ 2.06**	$ 2.32
Diluted	**$ 0.50**	$ 0.38	**$ 2.05**	$ 2.31
Dividends per common share declared	**$ 1.1525**	$ 1.0875	**$ 2.2825**	$ 2.1325

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

Emera Incorporated
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Net income	**$ 141**	$ 99	**$ 516**	$ 531
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment	**(126)**	(263)	**220**	(495)
Unrealized gains (losses) on net investment hedges (1) (2)	**25**	51	**(41)**	103
Cash flow hedges				
Net derivative gains (losses)	**3**	6	**5**	11
Less: reclassification adjustment for losses (gains) included in income (3)	**-**	1	**(6)**	5
Net effects of cash flow hedges	**3**	7	**(1)**	16
Unrealized gains (losses) on available-for-sale investment				
Unrealized gain (loss) arising during the period	**-**	3	**-**	7
Less: reclassification adjustment for (gains) losses recognized in income	**-**	(1)	**(4)**	(2)
Net unrealized holding gains (losses)	**-**	2	**(4)**	5
Net change in unrecognized pension and post-retirement benefit obligation (4)	**7**	8	**26**	21
Other comprehensive income (loss) (5)	**(91)**	(195)	**200**	(350)
Comprehensive income (loss)	**50**	(96)	**716**	181
Comprehensive income (loss) attributable to non-controlling interest	**-**	1	**3**	3
Comprehensive income (loss) of Emera Incorporated	**$ 50**	$ (97)	**$ 713**	$ 178

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

(1) Net of tax expense of $2 million (2017 - $9 million tax expense) for the three months ended September 30, 2018 and tax recovery of $7 million (2017 – $10 million tax expense) for the nine months ended September 30, 2018.

(2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.

(3) Net of tax expense of nil (2017 - nil tax expense) for the three months ended September 30, 2018 and tax recovery of $1 million (2017 – $1 million tax expense) for the nine months ended September 30, 2018.

(4) Net of tax expense of nil (2017 - nil tax expense) for the three months ended September 30, 2018 and tax expense of $1 million (2017 – $2 million tax expense) for the nine months ended September 30, 2018.

(5) Net of tax expense of $2 million (2017 - $9 million tax expense) for the three months ended September 30, 2018 and tax recovery of $7 million (2017 – $13 million tax expense) for the nine months ended September 30, 2018.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars	**September 30 2018**	December 31 2017
Assets		
Current assets		
Cash and cash equivalents	**$ 393**	$ 438
Restricted cash	**70**	65
Inventory	**430**	418
Derivative instruments (notes 11 and 12)	**177**	141
Regulatory assets (note 13)	**97**	138
Receivables and other current assets	**1,229**	1,326
	2,396	2,526
Property, plant and equipment, net of accumulated depreciation and amortization of $8,411 and $7,824, respectively	**18,301**	16,995
Other assets		
Deferred income taxes (note 7)	**190**	138
Derivative instruments (notes 11 and 12)	**72**	112
Regulatory assets (note 13)	**1,288**	1,238
Net investment in direct financing lease	**476**	481
Investments subject to significant influence (note 6)	**1,301**	1,215
Goodwill	**5,990**	5,805
Other long-term assets	**295**	261
	9,612	9,250
Total assets	**$ 30,309**	$ 28,771
Liabilities and Equity		
Current liabilities		
Short-term debt (note 16)	**$ 1,121**	$ 1,241
Current portion of long-term debt	**857**	741
Accounts payable	**1,159**	1,161
Derivative instruments (notes 11 and 12)	**317**	227
Regulatory liabilities (note 13)	**305**	226
Other current liabilities	**514**	350
	4,273	3,946
Long-term liabilities		
Long-term debt (note 17)	**13,642**	13,140
Deferred income taxes (note 7)	**1,098**	1,011
Derivative instruments (notes 11 and 12)	**109**	83
Regulatory liabilities (note 13)	**2,221**	2,242
Pension and post-retirement liabilities (note 15)	**544**	559
Other long-term liabilities	**670**	609
	18,284	17,644
Equity		
Common stock (note 8)	**5,768**	5,601
Cumulative preferred stock (note 19)	**1,004**	709
Contributed surplus	**83**	76
Accumulated other comprehensive income (loss) (note 10)	**10**	(188)
Retained earnings	**847**	891
Total Emera Incorporated equity	**7,712**	7,089
Non-controlling interest in subsidiaries	**40**	92
Total equity	**7,752**	7,181
Total liabilities and equity	**$ 30,309**	$ 28,771

Commitments and contingencies (note 18)

Approved on behalf of the Board of Directors

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

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Nine months ended September 30 **2018**	2017
Operating activities		
Net income	**$ 516**	$ 531
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**695**	637
Income from equity investments, net of dividends	**(64)**	(66)
Allowance for equity funds used during construction	**(14)**	(7)
Deferred income taxes, net	**8**	143
Net change in pension and post-retirement liabilities	**(1)**	(23)
Regulated fuel adjustment mechanism	**(10)**	49
Net change in fair value of derivative instruments	**122**	(259)
Net change in regulatory assets and liabilities	**64**	(169)
Net change in capitalized transportation capacity	**(79)**	110
Other operating activities, net	**-**	10
Changes in non-cash working capital (note 20)	**156**	85
Net cash provided by operating activities	**1,393**	1,041
Investing activities		
Additions to property, plant and equipment	**(1,544)**	(1,084)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(43)**	(183)
Other investing activities	**22**	(6)
Net cash used in investing activities	**(1,565)**	(1,273)
Financing activities		
Change in short-term debt, net	**91**	51
Proceeds from short-term debt with maturities greater than 90 days	**129**	-
Proceeds from long-term debt, net of issuance costs	**488**	39
Retirement of long-term debt	**(728)**	(48)
Net borrowings under committed credit facilities	**152**	253
Issuance of common stock, net of issuance costs	**8**	7
Issuance of preferred stock, net of issuance costs (note 19)	**291**	-
Dividends on common stock	**(256)**	(208)
Dividends on preferred stock	**(24)**	(21)
Other financing activities	**(30)**	(11)
Net cash provided by financing activities	**121**	62
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**11**	(21)
Net decrease in cash, cash equivalents and restricted cash	**(40)**	(191)
Cash, cash equivalents and restricted cash, beginning of period	**503**	491
Cash, cash equivalents and restricted cash, end of period	**$ 463**	$ 300
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 319**	$ 220
Short-term investments	**74**	1
Restricted cash	**70**	79
Cash, cash equivalents, and restricted cash	**$ 463**	$ 300

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

Emera Incorporated
Condensed Consolidated Statements of Changes in Equity (Unaudited)

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("AOCI")	Retained Earnings	Non-Controlling Interest	Total Equity
For the nine months ended September 30, 2018							
Balance, December 31, 2017	$ 5,601	$ 709	$ 76	$ (188)	$ 891	$ 92	$ 7,181
Net income of Emera Incorporated	-	-	-	-	515	1	516
Other comprehensive income, net of tax recovery of $7 million	-	-	-	198	-	2	200
Issuance of preferred stock, net of after-tax issuance costs	-	295	-	-	-	-	295
Dividends declared on preferred stock (Series A: $0.63880/share, Series B: $0.75700/share, Series C: $1.06381/share, Series E: $1.12500/share, Series F: $1.06250/share and Series H: $0.56132/share)	-	-	-	-	(36)	-	(36)
Dividends declared on common stock ($2.2825/share)	-	-	-	-	(528)	-	(528)
Common stock issued under purchase plan	143	-	-	-	-	-	143
Acquisition of non-controlling interest of ICD Utilities Limited ("ICDU")	22	-	6	-	-	(53)	(25)
Other	2	-	1	-	5	(2)	6
Balance, September 30, 2018	$ 5,768	$ 1,004	$ 83	$ 10	$ 847	$ 40	$ 7,752
For the nine months ended September 30, 2017							
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 106	$ 1,076	$ 112	$ 6,816
Net income of Emera Incorporated	-	-	-	-	522	9	531
Other comprehensive income (loss), net of tax expense of $13 million	-	-	-	(344)	-	(6)	(350)
Issuance of common stock, net of after-tax issuance costs	6	-	-	-	-	-	6
Dividends declared on preferred stock (Series A: $0.63880/share, Series B: $0.60320/share, Series C: $1.02500/share, Series E: $1.12500/share and Series F: $1.06250/share)	-	-	-	-	(28)	-	(28)
Dividends declared on common stock ($2.1325/share)	-	-	-	-	(451)	-	(451)
Common stock issued under purchase plan	128	-	-	-	-	-	128
Other	3	-	1	-	1	(6)	(1)
Balance, September 30, 2017	$ 4,875	$ 709	$ 76	$ (238)	$ 1,120	$ 109	$ 6,651

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

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 2018 and 2017

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

At September 30, 2018 Emera’s primary rate-regulated subsidiaries and investments included the following:

- Emera Florida and New Mexico represents TECO Energy, Inc. (“TECO Energy”), a holding company with regulated electric and gas utilities in Florida and New Mexico that include:
    - Tampa Electric Company (“TEC”), which holds the Tampa Electric Division (“Tampa Electric”), a vertically integrated regulated electric utility in West Central Florida, and Peoples Gas System Division (“PGS”), a regulated gas distribution utility operating across Florida;
    - New Mexico Gas Company, Inc. (“NMGC”), a regulated gas distribution utility serving New Mexico;
    - TECO Finance, Inc. (“TECO Finance”), a financing subsidiary of TECO Energy; and
    - SeaCoast Gas Transmission LLC (“SeaCoast”), a natural gas transmission company offering services in Florida.
- Nova Scotia Power Inc. (“NSPI”), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia;
- Emera Maine, a regulated electric transmission and distribution utility in the state of Maine;
- Emera Caribbean represents Emera (Caribbean) Incorporated (“ECI”), a holding company with regulated electric utilities that include:
    - The Barbados Light & Power Company Limited (“BLPC”), a vertically integrated utility and sole provider of electricity on the island of Barbados;
    - Grand Bahama Power Company Limited (“GBPC”), a vertically integrated utility operating on Grand Bahama Island;
    - a 51.9 per cent interest in Dominica Electricity Services Ltd. (“Domlec”), a vertically integrated utility on the island of Dominica; and
    - a 19.1 per cent indirect interest in St. Lucia Electricity Services Limited (“Lucelec”).
- Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy Canada, which expires in 2034;
- Emera Newfoundland & Labrador Holdings Inc. (“ENL”), focused on two transmission investments related to an 824 megawatt (“MW”) hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador being developed by Nalcor Energy and forecasted to be generating first power in 2019 and full power in 2020. ENL’s two investments are:
    - a 100 per cent investment in NSP Maritime Link Inc. (“NSPML”), which developed the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project went in service on January 15, 2018; and
    - a 49.5 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership (“LIL”), a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and the energization phase of the project began in June 2018.

- a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States.

At September 30, 2018 Emera's investments in other energy-related non-regulated companies included the following:

- Emera Energy, which consists of:
    - Emera Energy Services ("EES"), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
    - Bridgeport Energy, Tiverton Power and Rumford Power ("New England Gas Generating Facilities" or "NEGG"), power plants in the northeastern United States;
    - Bayside Power Limited Partnership ("Bayside Power"), a power plant in Saint John, New Brunswick;
    - Brooklyn Power Corporation ("Brooklyn Energy"), a power plant in Brooklyn, Nova Scotia; and
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a hydroelectric facility in northwestern Massachusetts.
- Emera US Finance LP, a wholly owned financing subsidiary of Emera;
- Emera Utility Services Inc., a utility services contractor primarily operating in Atlantic Canada; and
- other investments.

Basis of Presentation

These unaudited condensed consolidated interim financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). The significant accounting policies applied to these unaudited condensed consolidated interim financial statements are consistent with those disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2017, except as described in note 2.

In the opinion of management, these unaudited condensed consolidated interim financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2018.

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

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Actual results may differ significantly from these estimates.

Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year, primarily due to seasonal factors. Electricity and gas sales, and related transmission and distribution, vary over the year. 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. Certain quarters may also be impacted by weather and the number and severity of storms.

Revenue Recognition

Regulated electric revenue

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

Regulated gas revenue

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

Direct Finance Lease

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

Non-regulated revenue

Marketing and trading margin is comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management revenues. Revenues are recorded when obligations under terms of a contract are satisfied and are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

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

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

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

Other

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

Franchise Fees and Gross Receipts

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

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

2. CHANGE IN ACCOUNTING POLICY

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

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

Revenue from Contracts with Customers
On January 1, 2018, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers* and all the related amendments, which created a new, principle-based revenue recognition framework. The standard has been codified as Accounting Standards Codification ("ASC") Topic 606. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled to. The guidance requires additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

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

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

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

Clarifying the Definition of a Business
In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and is required to be applied prospectively. The Company adopted ASU 2017-01 effective January 1, 2018. There was no impact on the condensed consolidated financial statements as a result of the adoption of this standard.

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

The Company adopted ASU 2017-07 effective January 1, 2018 and September 30, 2017 balances have been retrospectively restated in the Condensed Consolidated Statements of Income. The standard allows the Company to use the amounts disclosed in its pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements. This change resulted in $7 million and $21 million of costs, previously presented within "Operating, maintenance and general", being reclassified to "Other income (expense), net" in the Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2017.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by Financial Accounting Standards Board (the "FASB"). The ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the 2017 audited consolidated financial statements, with updates noted below.

Leases

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

In January 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The Company will make this election. In July 2018, the FASB issued an amendment to ASC Topic 842 that permits companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The Company will make this election. Additionally, the Company will elect the option that allows the Company to not reassess whether any expired or existing contracts contain leases and will carry forward existing lease classification.

The standard will affect the Company’s financial position by increasing the assets and liabilities recorded relating to its operating leases, however, the ultimate impact of the new standard on the Company’s financial statements and disclosures has not yet been fully determined. In 2017, the Company developed and began execution of a project plan, which included holding training sessions with key stakeholders throughout the organization and gathering detailed information on existing lease arrangements. Activities currently being executed include evaluating the remaining available implementation alternatives, calculating the lease asset and liability balances associated with individual contractual arrangements and assessing the disclosure requirements. The Company will implement additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There will not be significant updates to systems as a result of implementation. The Company continues to monitor FASB amendments to ASC Topic 842.

Cloud Computing

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

4. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contribution of revenues, net income attributable to common shareholders and total assets, as reported to the Company's chief operating decision maker. Emera's six reportable segments are Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other (includes Emera Utility Services, ENL, Emera Brunswick Pipeline, Corporate, other strategic investments and certain holding companies).

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2018								
Operating revenues from external customers (1)	$ 964	$ 310	$ 74	$ 132	$ (4)	$ 19	$ -	$ 1,495
Inter-segment revenues (1)	-	-	-	-	5	9	(14)	-
Total operating revenues	964	310	74	132	1	28	(14)	1,495
Net income (loss) attributable to common shareholders	140	15	17	14	(54)	(14)	-	118
For the nine months ended September 30, 2018								
Operating revenues from external customers (1)	2,731	1,053	212	349	331	49	-	4,725
Inter-segment revenues (1)	-	2	-	-	12	27	(41)	-
Total operating revenues	2,731	1,055	212	349	343	76	(41)	4,725
Net income (loss) attributable to common shareholders	327	103	33	29	54	(67)	-	479
For the three months ended September 30, 2017								
Operating revenues from external customers (1)	$ 926	$ 283	$ 74	$ 109	$ 13	$ 21	$ -	$ 1,426
Inter-segment revenues (1)	-	-	-	-	3	14	(16)	1
Total operating revenues	926	283	74	109	16	35	(16)	1,427
Net income (loss) attributable to common shareholders	120	7	13	12	(39)	(32)	-	81
For the nine months ended September 30, 2017								
Operating revenues from external customers (1)	2,760	981	226	327	393	67	-	4,754
Inter-segment revenues (1)	-	2	-	-	10	28	(41)	(1)
Total operating revenues	2,760	983	226	327	403	95	(41)	4,753
Net income (loss) attributable to common shareholders	302	106	38	30	103	(85)	-	494

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

5. REVENUE

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

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2018								
Regulated								
Electric Revenue								
Residential	$ 431	$ 139	$ 27	$ 44	$ -	$ -	$ -	**$** 641
Commercial	213	95	22	75	-	-	-	405
Industrial	55	60	5	9	-	-	-	129
Other electric and regulatory deferrals	69	9	2	2	-	-	-	82
Other (1)	5	7	18	2	-	-	-	32
Regulated electric revenue	773	310	74	132	-	-	-	1,289
Gas Revenue								
Residential	74	-	-	-	-	-	-	74
Commercial	56	-	-	-	-	-	-	56
Industrial	12	-	-	-	-	-	-	12
Finance income (2)(3)	-	-	-	-	-	15	-	15
Other	45	-	-	-	-	-	-	45
Regulated gas revenue	187	-	-	-	-	15	-	202
Non-Regulated								
Marketing and trading margin (4)	-	-	-	-	6	-	-	6
Energy sales (4)	-	-	-	-	68	-	(5)	63
Capacity	-	-	-	-	38	-	-	38
Other	4	-	-	-	-	13	(9)	8
Mark-to-market (3)	-	-	-	-	(111)	-	-	(111)
Non-regulated revenue	4	-	-	-	1	13	(14)	4
Total operating revenues	**$ 964**	**$ 310**	**$ 74**	**$ 132**	**$ 1**	**$ 28**	**$ (14)**	**$ 1,495**

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

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the nine months ended September 30, 2018								
Regulated								
Electric Revenue								
Residential	$ 1,034	$ 532	$ 77	$ 115	$ -	$ -	$ -	**$** 1,758
Commercial	561	298	60	201	-	-	-	1,120
Industrial	155	171	12	23	-	-	-	361
Other electric and regulatory deferrals	251	33	12	5	-	-	-	301
Other (1)	10	21	50	5	-	-	(2)	84
Regulated electric revenue	2,011	1,055	211	349	-	-	(2)	3,624
Gas Revenue								
Residential	339	-	-	-	-	-	-	339
Commercial	211	-	-	-	-	-	-	211
Industrial	36	-	-	-	-	-	-	36
Finance income (2)(3)	-	-	-	-	-	41	-	41
Other	122	-	-	-	-	-	-	122
Regulated gas revenue	708	-	-	-	-	41	-	749
Non-Regulated								
Marketing and trading margin (4)	-	-	-	-	73	-	-	73
Energy sales (4)	-	-	-	-	217	-	(12)	205
Capacity	-	-	-	-	96	-	-	96
Other	12	-	1	-	-	35	(27)	21
Mark-to-market (3)	-	-	-	-	(43)	-	-	(43)
Non-regulated revenue	12	-	1	-	343	35	(39)	352
Total operating revenues	**$ 2,731**	**$ 1,055**	**$ 212**	**$ 349**	**$ 343**	**$ 76**	**$ (41)**	**$ 4,725**

(1) Other includes an immaterial amount of rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations

Remaining performance obligations primarily represent gas transportation contracts, lighting contracts and long-term steam supply arrangements with fixed contract terms. As of September 30, 2018, the aggregate amount of the transaction price allocated to remaining performance obligations was $357 million. As allowed by the practical expedient in ASC 606, this amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2033.

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value as at		Equity Income for the three months ended September 30		Equity Income for the nine months ended September 30		Percentage of Ownership
	September 30	December 31					
millions of Canadian dollars	**2018**	2017	**2018**	2017	**2018**	2017	**2018**
NSPML	**$ 553**	$ 510	**$ 10**	$ 10	**$ 40**	$ 26	100.0
LIL(1)	**523**	492	**11**	9	**31**	27	49.5
M&NP (2)	**152**	156	**4**	6	**17**	17	12.9
Lucelec (2)	**40**	39	**1**	-	**2**	2	19.1
Bear Swamp (3)	**-**	-	**13**	8	**27**	17	50.0
Other Investments	**33**	18	**2**	1	**4**	1	
	$ 1,301	$ 1,215	**$ 41**	$ 34	**$ 121**	$ 90	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total of all classes of units issued. Emera's percentage investment in the partnership capital of LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in the partnership capital of LIL will be determined upon completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.
(2) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method.
(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in Q4 2015. Bear Swamp's credit investment balance of $171 million (2017 - $188 million) is recorded in "Other long-term liabilities" on the Condensed Consolidated Balance Sheets.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 21). NSPML's consolidated summarized balance sheet is illustrated as follows:

As at	**September 30**	December 31
millions of Canadian dollars	**2018**	2017
Balance Sheet		
Current assets	**$ 116**	$ 225
Property, plant and equipment	**1,694**	1,720
Non-current assets	**126**	74
Total assets	**$ 1,936**	$ 2,019
Current liabilities	**$ 36**	$ 180
Long-term debt	**1,287**	1,287
Non-current liabilities	**60**	42
Equity	**553**	510
Total liabilities and equity	**$ 1,936**	$ 2,019

7. INCOME TAXES

The income tax provision differs from that computed using the statutory income tax rate for the following reasons:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Income before provision for income taxes	**$ 108**	$ 144	**$ 545**	$ 722
Statutory income tax rate	**31%**	31%	**31%**	31%
Income taxes, at statutory income tax rate	**34**	45	**169**	224
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(10)**	(5)	**(41)**	(40)
Foreign tax rate variance	**(17)**	16	**(34)**	35
Amortization of deferred income tax regulatory liabilities	**(7)**	-	**(24)**	-
Florida state tax apportionment adjustment	**(23)**		**(23)**	-
Tax effect of equity earnings	**(3)**	(3)	**(13)**	(9)
Financing deductions	**(1)**	(4)	**(3)**	(13)
Other	**(6)**	(4)	**(2)**	(6)
Income tax expense (recovery)	**$ (33)**	$ 45	**$ 29**	$ 191
Effective income tax rate	**(31)%**	31%	**5%**	26%

The statutory income tax rate of 31 per cent represents the combined Canadian federal and Nova Scotia and New Brunswick provincial corporate income tax rates, which are the relevant tax jurisdictions for Emera. The foreign tax rate variance reflects the reduction in the US federal corporate income tax rate.

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

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

The Company was required to revalue its US deferred income tax assets and liabilities based on the new 21 per cent tax rate at the date of enactment. The Company recognized $317 million income tax expense on December 31, 2017 as a result of the estimated revaluation of its US non-regulated net deferred income tax assets. The Company also reduced its US regulated net deferred income tax liabilities by an estimated $1.1 billion and recorded an equivalent regulatory liability since the benefit of lower US taxes is expected to be returned to customers over time as required by the Act or by order of the applicable regulator.

The Company provisionally revalued all of its US deferred tax assets and liabilities as of December 31, 2017, based on the rates they are expected to reverse at in the future, which is generally 21 per cent for US federal tax purposes. The December 31, 2017 balances of deferred tax assets and deferred tax liabilities that have been revalued are $1.3 billion and $1.8 billion, respectively. The Company continues to monitor certain aspects of the Act, including the valuation of refundable alternative minimum tax credits, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act. No measurement period adjustments have been recognized year-to-date in 2018.

The following reflects the composition of taxes on income from continuing operations presented in the Condensed Consolidated Statements of Income:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Income tax expense (recovery) – current	**$ 2**	$ 19	**$ 21**	$ 48
Income tax expense (recovery) – deferred	**(35)**	26	**8**	143
Income tax expense (recovery)	**$ (33)**	$ 45	**$ 29**	$ 191

NSPI and the Canada Revenue Agency ("CRA") are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62 million, including interest. NSPI has prepaid $23 million of the amount in dispute, as required by CRA.

Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years. Should NSPI receive similar notices of reassessment for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. NSPI continues to assess its options to resolve the dispute however the outcome of the Appeal process is not determinable at this time.

8. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars
Balance, December 31, 2017	228.77	$ 5,601
Conversion of Convertible Debentures (1)	0.01	-
Issuance of common stock (2)	0.45	22
Issued for cash under Purchase Plans at market rate	3.67	150
Discount on shares purchased under Dividend Reinvestment Plan	-	(7)
Options exercised under senior management share option plan	0.02	1
Employee Share Purchase Plan	-	1
Balance, September 30, 2018	**232.92**	**$ 5,768**

(1) As at September 30, 2018, a total of 52.15 million common shares of the Company were issued, representing conversion into common shares of more than 99.9 per cent of the Convertible Debentures.
(2) In Q1 2018, Emera issued 0.45 million common shares to facilitate the creation and issuance of 1.8 million depository receipts in connection with the ICDU share acquisition. The depository receipts are listed on the Bahamas International Securities Exchange.

9. EARNINGS PER SHARE

The following table reconciles the computation of basic and diluted earnings per share:

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Numerator				
Net income attributable to common shareholders	**$ 118.1**	$ 81.0	**$ 479.0**	$ 494.4
Diluted numerator	**118.1**	81.0	**479.0**	494.4
Denominator				
Weighted average shares of common stock outstanding	**232.4**	212.7	**231.1**	211.6
Weighted average deferred share units outstanding	**1.3**	1.1	**1.3**	1.1
Weighted average shares of common stock outstanding – basic	**233.7**	213.8	**232.4**	212.7
Stock-based compensation	**0.3**	0.6	**0.3**	0.5
Dividend reinvestment plan	**1.1**	0.8	**1.1**	0.8
Convertible Debentures	**0.1**	0.1	**0.1**	0.1
Weighted average shares of common stock outstanding – diluted	**235.2**	215.3	**233.9**	214.1
Earnings per common share				
Basic	**$ 0.51**	$ 0.38	**$ 2.06**	$ 2.32
Diluted	**$ 0.50**	$ 0.38	**$ 2.05**	$ 2.31

10. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss), net of tax, are as follows:

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change in available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the nine months ended September 30, 2018						
Balance, January 1, 2018	$ 29	$ 48	$ (3)	$ 3	$ (265)	$ (188)
Other comprehensive income (loss) before reclassifications	218	(41)	5	-	-	182
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	(6)	(4)	26	16
Net current period other comprehensive income (loss)	218	(41)	(1)	(4)	26	198
Balance, September 30, 2018	$ 247	$ 7	$ (4)	$ (1)	$ (239)	$ 10

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change in available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the nine months ended September 30, 2017						
Balance, January 1, 2017	$ 486	$ (49)	$ (21)	$ (1)	$ (309)	$ 106
Other comprehensive income (loss) before reclassifications	(489)	103	11	7	-	(368)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	5	(2)	21	24
Net current period other comprehensive income (loss)	(489)	103	16	5	21	(344)
Balance, September 30, 2017	$ (3)	$ 54	$ (5)	$ 4	$ (288)	$ (238)

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

For the millions of Canadian dollars	Affected line item in the Consolidated Financial Statements	Three months ended September 30 **2018**	2017	Nine months ended September 30 **2018**	2017
		Amounts reclassified from AOCI			
Losses (gain) on derivatives recognized as cash flow hedges					
Power and gas swaps	Non-regulated fuel for generation and purchased power	**$ 1**	$ -	**$ (2)**	$ (3)
Foreign exchange forwards	Operating revenue – regulated	**(1)**	1	**(5)**	7
Total before tax		**-**	1	**(7)**	4
	Income tax expense (recovery)	**-**	-	**1**	1
Total net of tax		**$ -**	$ 1	**$ (6)**	$ 5
Net change in available-for-sale investments					
	Other income (expenses), net	**-**	(1)	**-**	(2)
	Retained earnings (1)	**-**	-	**(4)**	-
Total before tax		**-**	(1)	**(4)**	(2)
	Income tax expense (recovery)	**-**	-	**-**	-
Total net of tax		**-**	(1)	**(4)**	(2)
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses (gains)	Operating, maintenance and general ("OM&G")	**$ 10**	$ 10	**$ 33**	$ 25
Past service costs (gains)	OM&G	**(3)**	(2)	**(6)**	(6)
Total before tax		**7**	8	**27**	19
	Income tax expense (recovery)	**-**	-	**(1)**	2
Total net of tax		**$ 7**	$ 8	**$ 26**	$ 21
Total reclassifications out of AOCI, net of tax, for the period		**$ 7**	$ 8	**$ 16**	$ 24

(1) Related to the adoption of ASU 2016-01, Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities. Refer to note 2 Change in Accounting Policy.

11. DERIVATIVE INSTRUMENTS

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange fluctuations on foreign currency denominated purchases and sales; and
- interest rate fluctuations on debt securities.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered “derivatives”. The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the normal purchases normal sales (“NPNS”) exemption are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Company’s business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. Specifically for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in fair value from cash flow hedges is recognized in net income in the reporting period.

   Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

3. Derivatives entered into by Tampa Electric, PGS, NMGC, NSPI, Emera Maine and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates.

4. Derivatives that do not meet any of the above criteria are designated as held-for-trading (“HFT”) derivatives and are recorded on the balance sheet at fair value, with changes normally recorded in net income of the period, unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**September 30 2018**	December 31 2017	**September 30 2018**	December 31 2017
Cash flow hedges				
Power swaps	**$ 1**	$ 5	**$ 1**	$ 2
Foreign exchange forwards	**-**	2	**2**	5
	1	7	**3**	7
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**116**	137	**11**	10
Power purchases	**4**	5	**1**	3
Natural gas purchases and sales	**5**	6	**5**	7
Heavy fuel oil purchases	**45**	15	**5**	4
Foreign exchange forwards	**22**	32	**2**	4
Physical natural gas and biofuel energy purchases and sales	**-**	-	**1**	-
	192	195	**25**	28
HFT derivatives				
Power swaps and physical contracts	**62**	125	**80**	162
Natural gas swaps, futures, forwards, physical contracts	**125**	105	**450**	294
	187	230	**530**	456
Other derivatives				
Interest rate swap	**1**	2	**-**	-
	1	2	**-**	-
Total gross current derivatives	**381**	434	**558**	491
Impact of master netting agreements with intent to settle net or simultaneously	**(132)**	(181)	**(132)**	(181)
	249	253	**426**	310
Current	**177**	141	**317**	227
Long-term	**72**	112	**109**	83
Total derivatives	**$ 249**	$ 253	**$ 426**	$ 310

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

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**September 30 2018**	December 31 2017	**September 30 2018**	December 31 2017
Regulatory deferral	**$ 16**	$ 14	**$ 16**	$ 14
HFT derivatives	**116**	167	**116**	167
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 132**	$ 181	**$ 132**	$ 181

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

The amounts related to cash flow hedges recorded in income and AOCI consisted of the following:

For the millions of Canadian dollars		Three months ended September 30 **2018**		2017
	Power Swaps	**Foreign Exchange Forwards**	Power Swaps	Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**$ (1)**	**$ -**	$ -	$ -
Realized gain (loss) in operating revenue – regulated	**-**	**1**		(1)
Total gains (losses) in net income	**$ (1)**	**$ 1**	$ -	$ (1)

For the millions of Canadian dollars		Nine months ended September 30 **2018**		2017
	Power Swaps	**Foreign Exchange Forwards**	Power Swaps	Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**$ 2**	**$ -**	$ 3	$ -
Realized gain (loss) in operating revenue – regulated	**-**	**5**	-	(7)
Total gains (losses) in net income	**$ 2**	**$ 5**	$ 3	$ (7)

As at millions of Canadian dollars		**September 30 2018**		December 31 2017
	Power Swaps	**Foreign Exchange Forwards**	Power Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ (1)**	**$ (3)**	$ -	$ (3)

The Company expects $2 million of unrealized losses currently in AOCI to be reclassified into net income within the next 12 months, as the underlying hedged transactions settle.

As at September 30, 2018, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	**2018**	2019	2020
Foreign exchange forwards (USD) sales	$ 8	$ 30	$ 30

Regulatory Deferral

The Company has recorded the following changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the millions of Canadian dollars			**2018**			Three months ended September 30 2017
	Commodity swaps and forwards	**Physical natural gas and biofuel energy purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (8)**	**$ -**	**$ (1)**	$ (3)	$ 2	$ (2)
Unrealized gain (loss) in regulatory liabilities	**35**	**-**	**(4)**	22	-	(15)
Realized (gain) loss in regulatory liabilities	**2**	**-**	**-**	-	-	-
Realized (gain) loss in inventory (1)	**(18)**	**-**	**(3)**	(4)	-	(3)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(3)**	**-**	**(3)**	2	-	(3)
Total change in derivative instruments	**$ 8**	**$ -**	**$ (11)**	$ 17	$ 2	$ (23)

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

For the millions of Canadian dollars			**2018**			Nine months ended September 30 2017
	Commodity swaps and forwards	**Physical natural gas and biofuel energy purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (16)**	**$ (1)**	**$ 2**	$ (30)	$ (3)	$ (4)
Unrealized gain (loss) in regulatory liabilities	**76**	**-**	**10**	30	1	(32)
Realized (gain) loss in regulatory liabilities	**(3)**	**-**	**-**	(1)	-	-
Realized (gain) loss in inventory (1)	**(43)**	**-**	**(14)**	(12)	-	(26)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(5)**	**-**	**(6)**	(2)	-	(12)
Total change in derivative instruments	**$ 9**	**$ (1)**	**$ (8)**	$ (15)	$ (2)	$ (74)

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

Commodity Swaps and Forwards

As at September 30, 2018, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	2018 Purchases	2019-2022 Purchases
Coal (metric tonnes)	-	1
Natural Gas (Mmbtu)	18	6
Heavy fuel oil (bbls)	-	1

Foreign Exchange Swaps and Forwards

As at September 30, 2018, the Company had the following notional volumes of foreign exchange swaps and forward contracts related to commodity contracts that are expected to settle as outlined below:

	2018	2019-2020
Foreign exchange contracts (millions of US dollars)	$ 30	$ 171
Weighted average rate	1.1131	1.2061
% of USD requirements	60%	41%

The Company reassesses foreign exchange forecasted periodically and will enter into additional hedges or unwind existing hedges, as required.

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas, as well as power and natural gas swaps, forwards and futures, to economically hedge those physical contracts. These derivatives are all considered HFT.

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Power swaps and physical contracts in non-regulated operating revenues	**$ (1)**	$ (2)	**$ (11)**	$ 4
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(104)**	28	**55**	405
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for purchased power	**-**	-	**-**	8
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**2**	(1)	**2**	(2)
	$ (103)	$ 25	**$ 46**	$ 415

As at September 30, 2018, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2018	2019	2020	2021	2022
Natural gas purchases (Mmbtu)	128	243	102	70	51
Natural gas sales (Mmbtu)	103	132	29	9	2
Power purchases (MWh)	2	3	-	-	-
Power sales (MWh)	2	4	-	-	-

Other Derivatives

The Company has realized and unrealized gains (losses) with respect to cash flow hedges for which documentation requirements have not been met for the three months ended September 30, 2018 of nil (2017 - $2 million) and for the nine months ended September 30, 2018 of nil (2017 - $3 million).

As at September 30, 2018, the Company had interest rate swaps in place for the $250 million non-revolving term credit facility in Brunswick Pipeline for interest payments until the debt matures in 2019.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high risk accounts.

The Company assesses the potential for credit losses on a regular basis and where, appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at September 30, 2018, the Company had $124 million (December 31, 2017 - $90 million) in financial assets considered to be past due, which have been outstanding for an average 64 days. The fair value of these financial assets is $111 million (December 31, 2017 - $78 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric and gas revenue.

Cash Collateral

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

As at millions of Canadian dollars		**September 30** **2018**		December 31 2017
Cash collateral provided to others	**$**	**58**	$	119
Cash collateral received from others		**100**		99

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at September 30, 2018, the total fair value of these derivatives, in a liability position, was $426 million (December 31, 2017 – $310 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

12. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 11), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				September 30, 2018
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power swaps	$ 1	$ -	$ -	$ 1
	1	-	-	1
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	105	-	105
Power purchases	4	-	-	4
Natural gas purchases and sales	-	4	-	4
Heavy fuel oil purchases	9	31	-	40
Foreign exchange forwards	-	23	-	23
	13	163	-	176
HFT derivatives				
Power swaps and physical contracts	6	1	3	10
Natural gas swaps, futures, forwards, physical contracts and related transportation	(1)	37	25	61
	5	38	28	71
Other derivatives				
Interest rate swap	-	1	-	1
	-	1	-	1
Total assets	19	202	28	249
Liabilities				
Cash flow hedges				
Power swaps	1	-	-	1
Foreign exchange forwards	-	2	-	2
	1	2	-	3
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	1	-	-	1
Heavy fuel oil purchases	-	-	-	-
Natural gas purchases and sales	4	1	-	5
Foreign exchange forwards	-	2	-	2
Physical natural gas and biofuel energy purchases and sales	-	1	-	1
	5	4	-	9
HFT derivatives				
Power swaps and physical contracts	23	2	2	27
Natural gas swaps, futures, forwards and physical contracts	(1)	53	335	387
	22	55	337	414
Total liabilities	28	61	337	426
Net assets (liabilities)	$ (9)	$ 141	$ (309)	$ (177)

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

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2018 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 5**	**$ 23**	**$ 28**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(2)**	**2**	**-**
Balance, September 30, 2018	**$ 3**	**$ 25**	**$ 28**

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2018 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 2**	**$ 196**	**$ 198**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**139**	**139**
Balance, September 30, 2018	**$ 2**	**$ 335**	**$ 337**

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2018 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 9**	**$ 25**	**$ 34**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(6)**	**-**	**(6)**
Balance, September 30, 2018	**$ 3**	**$ 25**	**$ 28**

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2018 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ (4)**	**$ 187**	**$ 183**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**6**	**148**	**154**
Balance, September 30, 2018	**$ 2**	**$ 335**	**$ 337**

The Company evaluates the observable inputs of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the three months and nine months ended September 30, 2018, there were no transfers between levels.

Significant unobservable inputs used in the fair value measurement of Emera’s natural gas and power derivatives include third-party-sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Where possible, Emera also sources multiple broker prices in an effort to evaluate and substantiate these unobservable inputs. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at					September 30, 2018	
millions of Canadian dollars		**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets						
HFT derivatives – Power swaps and physical contracts	**$**	**1**	Modelled pricing	Third-party pricing	$22.90-$101.75	$45.21
				Probability of default	0.03%-1.71%	0.51%
				Discount rate	0.19%-14.37%	7.08%
		2	Modelled pricing	Third-party pricing	$22.37-$36.26	$32.02
				Probability of default	0.12%-0.29%	0.12%
				Discount rate	0.83%-2.84%	1.88%
				Correlation factor	86.08%-86.08%	86.08%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts		**6**	Modelled pricing	Third-party pricing	$2.13-$6.39	$3.11
				Probability of default	0.01%-2.55%	0.47%
				Discount rate	0.06%-32.88%	7.03%
		19	Modelled pricing	Third-party pricing	$1.98-$14.84	$9.10
				Basis adjustment	$0.09-$3.43	$3.02
				Probability of default	0.03%-1.13%	0.06%
				Discount rate	0.02%-9.10%	0.57%
Total assets	**$**	**28**				
Liabilities						
HFT derivatives – Power swaps and physical contracts	**$**	**2**	Modelled pricing	Third-party pricing	$18.88-$27.27	$22.38
				Probability of default	0.12%-0.29%	0.19%
				Discount rate	0.19%-3.46%	1.91%
				Correlation factor	86.08%-86.08%	86.08%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		**253**	Modelled pricing	Third-party pricing	$1.65-$14.03	$6.13
				Own credit risk	0.03%-1.02%	0.12%
				Discount rate	0.02%-13.72%	2.84%
		82	Modelled pricing	Third-party pricing	$1.49-$15.53	$10.28
				Basis adjustment	$0.09-$3.43	$2.35
				Own credit risk	0.01%-1.13%	0.05%
				Discount rate	0.02%-9.77%	0.97%
Total liabilities	**$**	**337**				
Net assets (liabilities)	**$**	**(309)**				

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

As at millions of Canadian dollars		**Carrying Amount**		**Fair Value**		**Level 1**		**Level 2**		**Level 3**		**Total**
September 30, 2018	**$**	**14,499**	**$**	**15,104**	**$**	**-**	**$**	**14,308**	**$**	**796**	**$**	**15,104**
December 31, 2017	$	13,881	$	15,217	$	69	$	14,346	$	802	$	15,217

The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations. An after-tax foreign currency gain of $25 million was recorded in Other Comprehensive Income for the three months ended September 30, 2018 (2017 – $51 million gain after-tax). An after-tax foreign currency loss of $41 million was recorded in Other Comprehensive Income for the nine months ended September 30, 2018 (2017 – $103 million gain after-tax). There was no ineffectiveness for the three and nine months ended September 30, 2018 (2017 – nil).

13. REGULATORY ASSETS AND LIABILITIES

A summary of the Company's regulatory assets and liabilities is provided below. For a detailed description regarding the nature of the Company's regulatory assets and liabilities, refer to note 16 in Emera's 2017 annual audited consolidated financial statements.

As at millions of Canadian dollars		**September 30 2018**		December 31 2017
Regulatory assets				
Deferred income tax regulatory assets	**$**	**746**	$	667
Pension and post-retirement medical plan		**338**		345
Cost-recovery clauses		**45**		17
Environmental remediation		**30**		41
Unamortized defeasance costs		**27**		32
GBPC Hurricane Matthew restoration		**27**		28
Stranded cost recovery		**27**		25
2015 demand side management deferral		**25**		28
Storm reserve		**-**		59
Debt basis adjustment		**11**		13
Deferrals related to derivative instruments		**11**		15
Deferred bond refinancing costs		**7**		7
Other		**91**		99
	$	**1,385**	$	1,376
Current	**$**	**97**	$	138
Long-term		**1,288**		1,238
Total regulatory assets	**$**	**1,385**	$	1,376
Regulatory liabilities				
Deferred income tax regulatory liabilities	**$**	**1,154**	$	1,116
Accumulated reserve - cost of removal		**909**		894
Deferrals related to derivative instruments		**181**		182
NSPI fuel adjustment mechanism		**167**		177
Cost-recovery clauses		**38**		51
Storm reserve		**32**		-
Self-Insurance fund (note 21)		**28**		28
Other		**17**		20
	$	**2,526**	$	2,468
Current	**$**	**305**	$	226
Long-term		**2,221**		2,242
Total regulatory liabilities	**$**	**2,526**	$	2,468

Tax Reform and Storm Settlement

On March 1, 2018, the FPSC approved a settlement agreement filed by Tampa Electric authorizing the utility to net the estimated amount of storm cost recovery against its return of estimated 2018 US tax reform benefits to customers, effective April 1, 2018. In Q1 2018, Tampa Electric recorded OM&G expense and a regulatory liability of $19 million USD to offset tax reform benefits. Beginning April 1, 2018, this deferral of first quarter tax reform benefits is being amortized over the balance of the year as a credit against the recognition of storm expense. In total, OM&G expense due to the allowed netting of the storm cost recovery with tax reform benefits, net of amortization of first quarter tax reform benefits, was approximately $32 million USD for Q3 2018 and $80 million USD year-to-date. The storm reserve liability was $25 million USD at the end of Q3 2018.

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

On September 12, 2018, the FPSC approved a settlement agreement filed by PGS authorizing the utility to amortize $11 million USD of its manufactured gas plant environmental (“MGP”) regulatory asset and net it against its estimated 2018 tax reform benefits. Beginning in January 2019, PGS will lower base rates by $12 million USD to reflect the impact of tax reform.

Emera Maine Rate Case

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

14. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Intercompany balances and intercompany transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. All material amounts are under normal interest and credit terms.

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

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Condensed Consolidated Statements of Income. NSPI’s expense is reported in Operating expenses, Regulated fuel for generation and purchased power, totalling $25 million for the three months ended September 30, 2018 (2017 – nil) and $76 million for the nine months ended September 30, 2018 (2017 - nil). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments.

- Natural gas transportation capacity purchases from M&NP are reported in the Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $6 million for the three months ended September 30, 2018 (2017 - $4 million) and $22 million for the nine months ended September 30, 2018 (2017 - $20 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, 2018 and at December 31, 2017.

15. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, Maine, Connecticut, Massachusetts, Rhode Island, New Mexico, Barbados, Dominica and Grand Bahama Island. For details of the Company’s employee benefit plan, refer to note 20 in Emera’s 2017 annual audited consolidated financial statements.

Emera's net periodic benefit cost included the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Defined benefit pension plans				
Service cost	**$ 13**	$ 12	**$ 38**	$ 36
Non-service cost				
Interest cost	**24**	25	**71**	75
Expected return on plan assets	**(34)**	(31)	**(103)**	(97)
Current year amortization of:				
Actuarial losses	**10**	10	**32**	29
Past service gains	**(1)**	(1)	**(1)**	(1)
Regulated asset	**5**	3	**15**	12
Special termination benefits	**-**	-	**1**	-
Total non-service costs	**4**	6	**15**	18
Total defined benefit pension plans	**17**	18	**53**	54
Non-pension benefit plans				
Service cost	**1**	1	**4**	4
Non-service cost				
Interest cost	**4**	4	**10**	11
Expected return on plan assets	**(1)**	(1)	**(2)**	(2)
Current year amortization of:				
Actuarial losses	**-**	1	**1**	2
Past service gains	**(2)**	(2)	**(5)**	(6)
Regulated asset	**1**	-	**2**	(1)
Total non-service costs	**2**	2	**6**	4
Total non-pension benefit plans	**3**	3	**10**	8
Total defined benefit plans	**$ 20**	$ 21	**$ 63**	$ 62

Emera's total contributions related to these defined benefit pension plans and non-pension benefit plans for the three months ended September 30, 2018 were $13 million (2017 – $38 million), and for the nine months ended September 30, 2018 were $67 million (2017 – $132 million).

Annual employer contributions for the defined benefit pension plans are estimated to be $50 million for 2018.

16. SHORT-TERM DEBT

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. For details regarding short-term debt refer to note 23 in Emera's 2017 annual audited consolidated financial statements, and below for 2018 short-term debt financing activity.

Recent financing activities

Emera Florida and New Mexico

At September 30, 2018 TEC re-classified a $300 million USD 1-year term credit facility from short-term to long-term debt. This credit facility was reclassified, as it was repaid on October 11, 2018 using proceeds from a senior note issuance. Refer to note 17.

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

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

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

17. LONG-TERM DEBT

For details regarding long-term debt, refer to note 25 in Emera's 2017 annual audited consolidated financial statements, and below for 2018 long-term debt financing activity.

Recent financing activities

Emera

On May 16, 2018, Emera filed a $750 million debt and preferred equity shelf prospectus, providing the Company with access to raise long-term debt and preferred equity. On May 31, 2018, preferred shares were issued under this base shelf prospectus for gross proceeds of $300 million (see note 19). As at September 30, 2018 the Company has $450 million available for issuance under this prospectus, which expires on June 16, 2020.

Emera Florida and New Mexico

On October 4, 2018, TEC completed a $375 million USD 30-year senior notes issuance. The notes bear interest at a rate of 4.45 per cent and have a maturity date of June 15, 2049. Proceeds from this issuance were used to repay a $300 million USD 1-year term credit facility. This credit facility was classified as long-term debt at September 30, 2018. Refer to note 16.

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

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

Emera Maine

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

ECI

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

18. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2018, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2018	2019	2020	2021	2022	Thereafter	Total
Purchased power (1)	$ 62	$ 220	$ 218	$ 223	$ 223	$ 2,386	$ 3,332
Transportation (2)	127	397	314	208	193	1,566	2,805
Capital projects	286	326	143	32	3	3	793
Fuel and gas supply	155	297	88	46	6	3	595
Long-term service agreements (3)	24	91	51	50	39	278	533
Equity investment commitments (4)	-	-	190	-	-	-	190
Leases and other (5)	33	18	15	10	8	71	155
Demand side management	11	12	1	-	-	-	24
	$ 698	$ 1,361	$ 1,020	$ 569	$ 472	$ 4,307	$ 8,427

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.

(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.

(3) Maintenance of certain generating equipment, services related to a generation facility and wind operating agreements, outsourced management of computer and communication infrastructure and vegetation management.

(4) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.

(5) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. The UARB has approved NSPI to pay NSPML approximately $110 million and $111 million in 2018 and 2019, respectively. After 2019, the timing and amounts payable to NSPML will be subject to a regulatory filing with the UARB which will be filed no later than 2019.

B. Legal Proceedings

Emera Florida and New Mexico

TECO Coal

TECO Coal was sold by TECO Energy on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"), prior to Emera's acquisition of TECO Energy. On March 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified. The claim asserted breach of certain representations, and fraud and willful misconduct in connection therewith, of the Securities Purchase Agreement dated September 21, 2015 by and between TECO Diversified and Cambrian related to the purchase of TECO Coal by Cambrian. On March 7, 2018, TECO Diversified and Cambrian reached a global settlement agreement on mutually acceptable terms and conditions, having no material adverse effect on TECO Diversified. This matter is now considered closed.

TECO Guatemala Holdings ("TGH")

In 2013, the International Centre for the Settlement of Investment Disputes ("ICSID") Tribunal hearing the arbitration claim of TGH, a wholly owned subsidiary of TECO Energy, against the Republic of Guatemala (Guatemala) under the Dominican Republic Central America – United States Free Trade Agreement, issued an award in the case ("the Award"). The ICSID Tribunal unanimously found in favour of TGH and awarded damages to TGH of approximately $21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus two per cent. This award was upheld in subsequent annulment proceedings in 2016 and, in addition, TGH's application for partial annulment of the award was granted, and Guatemala was ordered to pay certain costs relating to the annulment proceedings. As a result, TGH had the right to resubmit its arbitration claim against Guatemala to seek additional damages (in addition to the previously awarded $21 million USD), as well as additional interest on the $21 million USD, and its full costs relating to the original arbitration and the new arbitration proceeding.

On September 23, 2016, TGH filed a request for resubmission to arbitration. On October 3, 2016, ICSID issued a notice of registration for TGH's request for resubmission. A new tribunal has been constituted and it issued its first procedural order. TGH's memorial was filed on September 1, 2017. Guatemala's counter-memorial was filed on February 2, 2018. TGH filed its reply memorial on May 30, 2018. Guatemala filed its reply on September 26, 2018. A hearing is scheduled for March 2019. A decision is expected from the tribunal in 2020. In addition, TGH has sued Guatemala in Washington, D.C. court to enforce the $21 million USD due and owing. Guatemala's motion to dismiss the enforcement action was denied. Results to date do not reflect any benefit.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at September 30, 2018, TEC has estimated its ultimate financial liability to be $36 million ($28 million USD), primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Condensed Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs. Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Emera Maine

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

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

On October 16, 2018, the FERC issued an order that addresses all four complaint proceedings. The FERC order proposes a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding is a 10.41 per cent base ROE for the ISO-NE OATT. Parties have 60 days to comment on the new methodology and its application to the four pending complaint proceedings. No new or additional reserves have been made with respect to all four pending complaints due to uncertainty.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Principal Financial Risks and Uncertainties

In this section, Emera describes some of the principal financial risks management believes could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 11 and note 12.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach to risk management.

Foreign Exchange Risk

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

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and projects. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes, or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries are included in AOCI.

Capital Market and Liquidity Risk

Emera's operations and projects in development require significant capital investments in property, plant and equipment. Consequently, Emera is an active participant in the debt and equity markets. Any disruption in capital markets could have a material impact on Emera's ability to fund its operations. Capital markets are global in nature and are affected by numerous events throughout the world economy. Capital market disruptions could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, and liquidity. A change to a credit rating as a result of changes in any of these items could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs will be financed through internally generated cash flows, select asset sales, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed ordinary course capital needs.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. While regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. Fuel contracts may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. US tax reform legislation was enacted on December 22, 2017. The Company continues to monitor certain aspects of the Act including interest deductibility and the valuation of refundable alternative minimum tax credits as some of the specific details have yet to be clarified. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

D. Guarantees and Letters of Credit

As at September 30, 2018, Emera had several significant guarantees and letters of credit on behalf of third parties outstanding. The following guarantees and letters of credit are not included within the Condensed Consolidated Balance Sheets as at September 30, 2018:

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

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian was obligated to file, in respect of each mining permit, applications in connection with the change of control with the appropriate governmental entities. As each application was approved, Cambrian was required to post a bond or other appropriate collateral in order to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. In April 2018, all of the TECO Coal bonds were released and returned.

Emera has standby letters of credit in the amount of $48 million USD to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in February 2019 and is renewed annually. The amount committed as of September 30, 2018 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under an unfunded pension plan. The letter of credit expires in June 2019 and is renewed annually. The amount committed as at September 30, 2018 was $49 million CAD.

19. CUMULATIVE PREFERRED STOCK

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

Issued and Outstanding:	Issued and Outstanding	Net Proceeds
Balance, December 31, 2017	29,000,000	$ 709
Issuance of First Preferred Shares Series H	12,000,000	$ 295
Balance, September 30, 2018	**41,000,000**	**$ 1,004**

First Preferred Shares, Series H

On May 31, 2018, Emera issued 12 million, 4.90 per cent Cumulative Minimum Rate Reset First Preferred Shares, Series H ("First Preferred Shares, Series H") at $25.00 per share for gross proceeds of $300 million ($295 million, net of after-tax issuance costs).

Characteristics of the first Preference Shares are as follows:

First Preference Shares (1)(2)	Initial Yield (%)	Annual Dividend ($)	Minimum Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a one for one basis
Minimum rate reset (3)(4)						
Series H	4.90	1.2250	4.90	August 15, 2023	25.00	Series I

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.
(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.
(3) On the conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield provided that such rate shall not be less than 4.90 per cent.
(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Floating Rate First Preference Shares, Series I of the Company. The floating quarterly dividend rate on the Series I shares will be equal to the sum of the T-Bill rate plus 2.54 per cent.

First Preference Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends will be deducted on the Consolidated Statements of Income immediately before arriving at "Net earnings attributable to common shareholders" and will be shown on the Consolidated Statement of Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

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

As at August 15, 2018, the holders of the First Preferred Shares Series C, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividend per share is $1.1802 (4.721%) per annum, payable quarterly, during the five-year period commencing on August 15, 2018 to and including August 14, 2023.

20. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Nine months ended September 30 **2018**	2017
Changes in non-cash working capital:		
Inventory	**$ (4)**	$ (5)
Receivables and other current assets	**203**	82
Accounts payable	**(54)**	(71)
Other current liabilities	**11**	79
Total non-cash working capital	**$ 156**	$ 85
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 135**	$ 123
Issuance of depository receipts	**$ 22**	$ -

21. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any Variable Interest Entities (“VIE”). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

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

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. In Q2 2014, when the critical milestones were achieved, Nalcor Energy was deemed the beneficiary of the asset for financial reporting purposes as they have authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a Self-Insurance Fund ("SIF"), primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. Any withdrawal of SIF fund assets by the Company would be subject to existing regulations. Emera's consolidated VIE in the SIF is recorded as an "Other long-term assets", "Restricted cash" and "Regulatory liabilities" on the Condensed Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**September 30, 2018**		December 31, 2017	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 553**	**$ 59**	$ 510	$ 67

22. COMPARATIVE INFORMATION

These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

23. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through November 8, 2018, the date the financial statements were issued.