EMERA INCORPORATED

Unaudited Condensed Consolidated Interim Financial Statements

September 30, 2016 and 2015

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	
	2016	2015	**2016**	2015
Operating revenues				
Regulated electric	**$ 1,246**	$ 503	**$ 2,301**	$ 1,620
Regulated gas	**192**	13	**217**	39
Non-regulated	**(51)**	127	**246**	399
Total operating revenues	**1,387**	643	**2,764**	2,058
Operating expenses				
Regulated fuel for generation and purchased power	**456**	186	**810**	615
Regulated cost of natural gas	**69**	-	**69**	-
Regulated fuel adjustment mechanism and fixed cost deferrals (note 6)	**6**	16	**48**	31
Non-regulated fuel for generation and purchased power	**64**	57	**243**	245
Non-regulated direct costs	**4**	5	**7**	15
Operating, maintenance and general	**423**	186	**746**	493
Provincial, state and municipal taxes	**85**	17	**118**	48
Depreciation and amortization	**204**	85	**376**	252
Total operating expenses	**1,311**	552	**2,417**	1,699
Income from operations	**76**	91	**347**	359
Income from equity investments (note 7)	**23**	24	**79**	82
Other income (expenses), net (note 8)	**14**	3	**169**	26
Interest expense, net (note 9)	**233**	49	**416**	142
Income (loss) before provision for income taxes	**(120)**	69	**179**	325
Income tax expense (recovery) (note 10)	**(44)**	12	**(16)**	72
Net income (loss)	**(76)**	57	**195**	253
Non-controlling interest in subsidiaries	**5**	7	**10**	18
Net income (loss) of Emera Incorporated	**(81)**	50	**185**	235
Preferred stock dividends	**14**	15	**28**	30
Net income (loss) attributable to common shareholders	**$ (95)**	$ 35	**$ 157**	$ 205
Weighted average shares of common stock outstanding (in millions) (note 12)				
Basic	**182.8**	146.0	**160.5**	145.4
Diluted	**182.8**	147.1	**162.0**	146.5
Earnings per common share (note 12)				
Basic	**$ (0.52)**	$ 0.24	**$ 0.98**	$ 1.41
Diluted	**$ (0.52)**	$ 0.24	**$ 0.97**	$ 1.40
Dividends per common share declared	**$ 1.0450**	$ 0.8750	**$ 1.9950**	$ 1.6625

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	
	2016	2015	**2016**	2015
Net income (loss)	**$ (76)**	$ 57	**$ 195**	$ 253
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	**58**	160	**(121)**	332
Unrealized gains (losses) on net investment hedges (2)	**(13)**	-	**(13)**	-
Cash flow hedges				
Net derivative gains (losses) (3)	**(3)**	(13)	**14**	(26)
Less: reclassification adjustment for losses (gains) included in income (4)	**3**	4	**7**	4
Net effects of cash flow hedges	**-**	(9)	**21**	(22)
Unrealized gains (losses) on available-for-sale investment				
Unrealized gain (loss) arising during the period	**3**	(4)	**3**	(4)
Less: reclassification adjustment for (gains) losses recognized in income (5)	**(4)**	-	**(4)**	-
Net unrealized holding gains (losses)	**(1)**	(4)	**(1)**	(4)
Net change in unrecognized pension and post-retirement benefit obligation (6)	**12**	10	**29**	46
Other equity method reclassification adjustment (7)	**-**	-	**(46)**	-
Other comprehensive income (loss) (8)	**56**	157	**(131)**	352
Comprehensive income (loss)	**(20)**	214	**64**	605
Comprehensive income (loss) attributable to non-controlling interest	**6**	19	**5**	40
Comprehensive income (loss) of Emera Incorporated	**$ (26)**	$ 195	**$ 59**	$ 565

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

1) Net of tax recovery of nil (2015 - nil tax expense) for the three months ended September 30, 2016 and tax recovery of $3 million (2015 – $3 million tax expense) for the nine months ended September 30, 2016.
2) The Company has designated $1.2 billion United States dollar dominated 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 $2 million (2015 - nil tax expense) for the three months ended September 30, 2016 and tax expense of $3 million (2015 – $1 million tax expense) for the nine months ended September 30, 2016.
4) Net of tax expense of $1 million (2015 - nil tax expense) for the three months ended September 30, 2016 and tax expense of nil (2015 – $1 million tax recovery) for the nine months ended September 30, 2016.
5) Net of tax expense of nil (2015 - nil tax expense) for the three months ended September 30, 2016 and tax expense of nil (2015 – nil tax expense) for the nine months ended September 30, 2016.
6) Net of tax recovery of $2 million (2015 - nil tax expense) for the three months ended September 30, 2016 and tax recovery of $2 million (2015 – $9 million tax expense) for the nine months ended September 30, 2016.
7) Net of tax recovery of nil (2015 - nil tax recovery) for the three months ended September 30, 2016 and tax recovery of $9 million (2015 – nil tax recovery) for the nine months ended September 30, 2016.
8) Net of tax expense of $1 million (2015 - nil tax expense) for the three months ended September 30, 2016 and tax recovery of $11 million (2015 – $12 million tax expense) for the nine months ended September 30, 2016.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at	September 30	December 31
millions of Canadian dollars	**2016**	2015
Assets		
Current assets		
Cash and cash equivalents	**$ 415**	$ 1,073
Restricted cash	**17**	19
Receivables, net (note 14)	**819**	578
Income taxes receivable	**37**	12
Inventory (note 15)	**477**	314
Derivative instruments (notes 16 and 17)	**109**	250
Regulatory assets (notes 6 and 18)	**68**	94
Prepaid expenses	**68**	18
Due from related parties (note 19)	**5**	2
Other current assets	**42**	236
Total current assets	**2,057**	2,596
Property, plant and equipment, net of accumulated depreciation and amortization of $7,598 and $3,737, respectively (note 20)	**16,658**	6,469
Other assets		
Income taxes receivable	**48**	49
Deferred income taxes	**95**	32
Derivative instruments (notes 16 and 17)	**121**	168
Pension and post-retirement assets (note 21)	**9**	9
Regulatory assets (notes 6 and 18)	**1,257**	605
Net investment in direct financing lease	**486**	480
Investments subject to significant influence (note 7)	**829**	1,145
Investment securities (note 22)	**201**	116
Goodwill (note 23)	**6,021**	264
Due from related parties (note 19)	**3**	3
Other long-term assets	**169**	103
Total other assets	**9,239**	2,974
Total assets	**$ 27,954**	$ 12,039

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

Emera Incorporated
Condensed Consolidated Balance Sheets – (Unaudited) Continued

As at millions of Canadian dollars	**September 30** **2016**	December 31 2015
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 800**	$ 16
Current portion of long-term debt	**300**	274
Accounts payable	**1,102**	394
Income taxes payable	**15**	8
Derivative instruments (notes 16 and 17)	**129**	349
Regulatory liabilities (note 6 and note 18)	**288**	112
Pension and post-retirement liabilities (note 21)	**56**	7
Due to related party (note 19)	**2**	2
Other current liabilities (note 24)	**445**	205
Total current liabilities	**3,137**	1,367
Long-term liabilities		
Long-term debt (note 25)	**14,328**	3,735
Deferred income taxes	**1,570**	762
Convertible debentures (2015 – represented by instalment receipts) (note 11)	**10**	681
Derivative instruments (notes 16 and 17)	**157**	96
Regulatory liabilities (note 6 and note 18)	**1,252**	353
Asset retirement obligations	**120**	109
Pension and post-retirement liabilities (note 21)	**673**	303
Other long-term liabilities (note 7)	**443**	299
Total long-term liabilities	**18,553**	6,338
Commitments and contingencies (note 26)		
Equity		
Common stock, no par value, unlimited shares authorized, 201.33 million and 147.21 million shares issued and outstanding, respectively (note 11)	**4,358**	2,157
Cumulative preferred stock, Series A, B, C, E and F, par value $25 per share; unlimited shares authorized, 3.9 million, 2.1 million, 10 million, 5 million, and 8 million shares issued and outstanding, respectively	**709**	709
Contributed surplus	**75**	29
Accumulated other comprehensive income (loss) (note 13)	**6**	137
Retained earnings	**1,006**	1,168
Total Emera Incorporated equity	**6,154**	4,200
Non-controlling interest in subsidiaries (note 27)	**110**	134
Total equity	**6,264**	4,334
Total liabilities and equity	**$ 27,954**	$ 12,039

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard" *"Christopher G. Huskilson"*

Chair of the Board **President and Chief Executive Officer**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Nine months ended September 30 2016	2015
Operating activities		
Net income	**$ 195**	$ 253
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**383**	261
Income from equity investments, net of dividends	**(49)**	(24)
Allowance for equity funds used during construction	**(12)**	(3)
Deferred income taxes, net	**(51)**	8
Net change in pension and post-retirement liabilities	**(3)**	28
Regulated fuel adjustment mechanism and fixed cost deferrals	**49**	29
Net change in fair value of derivative instruments	**56**	(1)
Net change in regulatory assets and liabilities	**7**	(5)
Net change in capitalized transportation capacity	**184**	63
Foreign exchange loss	**47**	-
Gain on APUC sale of common shares and conversion of subscription receipts	**(235)**	-
Other operating activities, net	**44**	(18)
Changes in non-cash working capital (note 28)	**252**	(29)
Net cash provided by operating activities	**867**	562
Investing activities		
Acquisition, net of cash acquired (note 4)	**(8,409)**	-
Additions to property, plant and equipment	**(593)**	(293)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(171)**	(68)
Net proceeds on sale of investments subject to significant influence	**525**	282
Other investing activities	**41**	(22)
Net cash used in investing activities	**(8,607)**	(101)
Financing activities		
Change in short-term debt, net	**(24)**	(278)
Proceeds from long-term debt, net of issuance costs	**6,228**	425
Proceeds from convertible debentures, net of issuance costs (2015 – represented by instalment receipts) (note 11)	**1,414**	593
Retirement of long-term debt	**(18)**	(15)
Net borrowings (repayments) under committed credit facilities	**(233)**	(490)
Issuance of common stock, net of issuance costs	**20**	7
Dividends on common stock	**(155)**	(116)
Dividends on preferred stock	**(21)**	(23)
Dividends paid by subsidiaries to non-controlling interest	**(5)**	(11)
Other financing activities	**(49)**	(16)
Net cash provided by financing activities	**7,157**	76
Effect of exchange rate changes on cash and cash equivalents	**(75)**	37
Net (decrease) increase in cash and cash equivalents	**(658)**	574
Cash and cash equivalents, beginning of period	**1,073**	221
Cash and cash equivalents, end of period	**$ 415**	**$** 795
Cash and cash equivalents consists of:		
Cash	**$ 353**	**$** 721
Short-term investments	**62**	74
Cash and cash equivalents	**$ 415**	**$** 795

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	Emera Total Equity	Non-Controlling Interest	Total Equity
For the nine months ended September 30, 2016								
Balance, December 31, 2015	$ 2,157	$ 709	$ 29	$ 137	$ 1,168	$ 4,200	$ 134	$ 4,334
Net income of Emera Incorporated	-	-	-	-	185	185	10	195
Other comprehensive income (loss), net of tax recovery of $11 million	-	-	-	(127)	-	(127)	(5)	(132)
Issuance of common stock, net of after-tax issuance costs	2,112	-	-	-	-	2,112	-	2,112
Dividends declared on preferred stock (Series A: $0.47910/share, Series B: $0.28180/share, Series C: $0.65740/share, Series E: $0.81875/share and Series F: $0.81250/share)	-	-	-	-	(28)	(28)	-	(28)
Dividends declared on common stock ($1.9950/share)	-	-	-	-	(324)	(324)	-	(324)
Common stock issued under purchase plan	69	-	-	-	-	69	-	69
Senior management stock options exercised	16	-	(1)	-	-	15	-	15
Stock option expense	-	-	1	-	-	1	-	1
Employee share purchase plan	1	-	-	-	-	1	-	1
Beneficial conversion feature, net of tax (note 9)	-	-	43	-	-	43	-	43
Preferred dividends paid and payable by subsidiaries to non-controlling interest	-	-	-	-	-	-	(4)	(4)
Common dividends paid and payable by subsidiaries to non-controlling interest	-	-	-	-	-	-	(1)	(1)
Acquisition of non-controlling interest of ECI	3	-	7	-	-	10	(24)	(14)
Other	-	-	(4)	(4)	5	(3)	-	(3)
Balance, September 30, 2016	$ 4,358	$ 709	$ 75	$ 6	$ 1,006	$ 6,154	$ 110	$ 6,264

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

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

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (“AOCI”)	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
For the nine months ended September 30, 2015								
Balance, December 31, 2014	$ 2,016	$ 709	$ 9	$ (347)	$ 1,012	$ 3,399	$ 307	$ 3,706
Net income of Emera Incorporated	-	-	-	-	235	235	18	253
Other comprehensive income (loss), net of tax expense of $12 million	-	-	-	329	-	329	22	351
Dividends declared on preferred stock (Series A: $0.5500/share, Series C: $0.5125/share, Series E: $0.5625/share and Series F: $0.53125/share)	-	-	-	-	(30)	(30)	-	(30)
Dividends declared on common stock ($1.6625/share)	-	-	-	-	(240)	(240)	-	(240)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(2)	(2)
Common stock issued under purchase plan	60	-	-	-	-	60	-	60
Senior management stock options exercised	2	-	-	-	-	2	-	2
Stock option expense	-	-	1	-	-	1	-	1
Other stock-based compensation	1	-	-	-	-	1	-	1
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(9)	(9)
Other	-	-	-	-	-	-	(1)	(1)
Balance, September 30, 2015	$ 2,079	$ 709	$ 10	$ (18)	$ 977	$ 3,757	$ 335	$ 4,092

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

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements
As at September 30, 2016 and 2015

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both the regulated and non-regulated operations of Emera Incorporated are as follows:

A. Nature of Operations

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

Emera's primary rate-regulated subsidiaries and investments at September 30, 2016 included the following:

- Emera Florida and New Mexico contains TECO Energy, Inc. ("TECO Energy"), a holding company with regulated electric and gas utilities in Florida and New Mexico, which was acquired on July 1, 2016. TECO Energy's holdings includes:
    - Tampa Electric Company ("TEC"), which holds the Tampa Electric Division ("Tampa Electric"), an integrated regulated electric utility which serves almost 730,000 customers in West Central Florida and Peoples Gas System Division, ("PGS") a regulated gas distribution utility which serves approximately 370,000 customers across Florida;
    - New Mexico Gas Company ("NMGC"), a regulated gas distribution utility which serves more than 518,000 customers across New Mexico;
    - TECO Finance, Inc. ("TECO Finance"), a wholly owned financing subsidiary of TECO Energy.
- Nova Scotia Power Inc. ("NSPI"), which is a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving 509,000 customers;
- Emera Maine provides electric transmission and distribution services to 158,000 customers in the State of Maine in the United States;
- Emera (Caribbean) Incorporated ("ECI") (100.0 per cent interest; December 31, 2015 – 95.5 per cent) includes:
    - The Barbados Light & Power Company Limited ("BLPC"), which is a vertically integrated utility and sole provider of electricity on the island of Barbados, serving 126,000 customers;
    - a 51.9 per cent interest (December 31, 2015 – 49.6 per cent indirect interest) through ECI in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica, serving 36,000 customers;
    - a 19.1 per cent indirect interest (December 31, 2015 – 18.2 per cent indirect interest) through ECI in St. Lucia Electricity Services Limited ("Lucelec"), which is a vertically integrated regulated electric utility in St. Lucia;
- a 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), which is a vertically integrated utility and sole provider of electricity on Grand Bahama Island, serving 19,000 customers;
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), which is 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 ("REC"), which expires in 2034;

- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), focused on two transmission investments related to the development of an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, scheduled to be generating first power in 2019 and full power in 2020. ENL's two investments are:
    - a 100 per cent interest in NSP Maritime Link Inc. ("NSPML"), which is developing 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 is scheduled to be completed in Q4 2017 and then be in service by January 1, 2018;
    - a 62.7 per cent investment (December 31, 2015 – 55.1 per cent) in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.4 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on 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. The investment in LIL is accounted for on the equity basis. This project is scheduled to go into service in Q2 2018.
- a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), which is a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States.

Emera Incorporated and its subsidiaries also own investments in other energy-related non-regulated companies, including:

- Emera Energy Inc. ("Emera Energy"), includes:
    - 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" ("NEGG")), comprising 1,090 MW of combined-cycle gas-fired electricity generating capacity in the northeastern United States;
    - Bayside Power Limited Partnership ("Bayside Power"), which is a 290 MW electricity generating facility in Saint John, New Brunswick;
    - Brooklyn Power Corporation ("Brooklyn Energy"), which is a 30 MW biomass co-generation merchant electricity facility in Brooklyn, Nova Scotia. Brooklyn Energy has a long-term purchase power agreement with NSPI;
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), which is a 600 MW pumped storage hydroelectric facility in northern Massachusetts.
- Emera Reinsurance Limited, which is a captive insurance company providing insurance and reinsurance to Emera and certain affiliates, to enable more cost efficient management of risk and deductible levels across Emera;
- Emera US Finance LP, a wholly owned financing subsidiary of Emera that issued multiple series of United States dollar denominated senior, unsecured notes for the purpose funding the acquisition of TECO Energy;
- Emera US Holdings Inc. ("EUSHI"), a wholly owned holding company for certain of Emera's assets located in the United States;
- Emera Utility Services Inc., which is a utility services contractor primarily operating in Atlantic Canada;
- a 4.7 per cent (December 31, 2015 – 19.6 per cent) investment in Algonquin Power & Utilities Corp. ("APUC"), which is a public company traded on the Toronto Stock Exchange under the symbol "AQN";
- and other investments.

B. 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 annual audited financial statements of Emera Incorporated's for the year ended December 31, 2015, except for adopted accounting policies described in note 1 (E) through 1 (I), and note 2.

Effective July 1, 2016, the acquisition date, the financial statements of TECO Energy were consolidated with Emera (note 4). TECO Energy's accounting policies align with those used by Emera's in its 2015 annual audited consolidated financial statements except certain TECO Energy-specific policies including policies approved by the regulator as described below.

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 Incorporated. 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, 2016.

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

C. Use of Management Estimates

The preparation of consolidated financial statements in accordance with United States generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, capitalized overhead, depreciation, asset removal costs, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs"), goodwill impairment assessments, valuation of investments and contingencies. Actual results may differ significantly from these estimates.

D. Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year, primarily due to seasonal factors. Electricity sales and related generation vary significantly over the year. The first quarter is typically the strongest period, reflecting colder weather and fewer daylight hours in the winter season in northeastern North America, where historically a substantial portion of Emera's electricity business is located. However, with the addition of Emera Florida and New Mexico, the third quarter will provide stronger earnings for Emera than prior to the acquisition due to the summer being the peak electricity season in Florida. Certain quarters may also be impacted by the number and severity of storms.

E. Investment Securities

Effective June 30, 2016, as a result of the sale of a portion of Emera's investment in APUC, the Company began recording its remaining investment in APUC as held-for-trading ("HFT") investment securities. Unrealized gains and losses arising from changes in the fair value of HFT investment securities are recognized in "Other income (expenses), net" on the Condensed Consolidated Statements of Income each period. Dividends on HFT equity securities are recognized on the Condensed Consolidated Statements of Income in "Other income (expenses), net".

F. Revenue Recognition

Revenues include amounts resulting from fuel and non-fuel cost recovery clauses at Tampa Electric, PGS and NMGC that provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, gas storage, interstate pipeline capacity and conservation costs for PGS and NMGC. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over- or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. BLPC and GBPC also recognize fuel cost recovery within revenues. NSPI includes over and under-recoveries of fuel costs within Regulated fuel adjustment mechanism and fixed cost deferrals on the Condensed Consolidated Statements of Income.

G. Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which the employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. Tampa Electric, PGS and NMGC recognize their unamortized gains and losses and past service costs in regulatory assets. Other Emera companies recognize the unamortized gains and losses and past service costs in AOCI.

H. Franchise Fees and Gross Receipts

Tampa Electric and PGS are allowed to recover certain costs on a dollar-for-dollar basis incurred from customers 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 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 Condensed 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 Condensed Consolidated Statement of Income.

I. Net Investment Hedges

The Company designates certain United States dollar dominated debt held in Canadian functional currency companies as hedges of net investments in United States dollar denominated foreign operations. The change in carrying amount of these investments, measured at the month-end spot rate, and the effective portion of the hedge of this exposure is recorded in Other Comprehensive Income. Any ineffectiveness is reflected in current period earnings.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and were adopted by the Company, with no material impact on its consolidated financial statements year-to-date in 2016, are described as follows:

Consolidation
In February 2015, the FASB issued Accounting Standard Update ("ASU") 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity ("VIE") characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities were subject to re-evaluation under the revised consolidation model.

Interest – Imputation of Interest
In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. The Company adopted this standard in Q1 2016 and December 31, 2015 balances have been retrospectively restated. This change resulted in $62.3 million of debt issuance costs, as at December 31, 2015, previously presented as "Other long-term assets", being reclassified as a deduction from the carrying amount of the related long-term debt and "Convertible debentures" on its Condensed Consolidated Balance Sheets.

In accordance with ASU 2015-15 *Interest: Imputation of Interest*, the Company continues to present debt issuance costs related to its revolving credit facilities and related instruments in "Other long-term assets" on its Condensed Consolidated Balance Sheets.

Compensation – Retirement Benefits
In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates.

Intangibles – Goodwill and Other – Internal-Use Software
In April 2015, the FASB issued ASU 2015-05, *Intangibles* **–** *Goodwill and Other* **–** *Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, the customer would account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer would account for the arrangement as a service contract. The guidance does not change USGAAP for a customer's accounting for service contracts.

Inventory – Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU 2015-11, *Inventory – Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. The Company early adopted in 2016 as permitted.

Derivatives and Hedging – Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships
In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships*. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The Company early adopted in 2016 as permitted.

Investments – Equity Method and Joint Ventures
In March 2016, the FASB issued ASU 2016-07, *Investments – Equity Method and Joint Ventures*, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. The Company early adopted in 2016 as permitted.

Compensation – Stock Compensation
In March 2016, the FASB issued ASU 2016-09, *Compensation – Stock Compensation* to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, accounting for forfeitures, classification of awards as either equity or liabilities and presentation on the statement of cash flows. The Company early adopted in 2016 as permitted.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework. 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 will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018. The Company has developed an implementation plan and is continuing to evaluate the available adoption methods and the impact of adoption of this standard on its consolidated financial statements and disclosures.

Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Leases
In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard 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 lease assets and lease liabilities on the balance sheet. The effect of leases on the Condensed Consolidated Statements of Income and the Condensed 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 is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments
In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective beginning in 2020, with early adoption permitted in 2019, and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows
In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for the company beginning in 2018, with early adoption permitted, and is required to be applied on a retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

4. ACQUISITION

TECO ENERGY INC.

On July 1, 2016, Emera acquired all of the outstanding common shares of TECO Energy Inc. for $27.55 USD per common share. The net cash purchase price totaled $8.4 billion ($6.5 billion USD), with an aggregate purchase price of $13.9 billion ($10.7 billion USD), including the assumption of $5.5 billion ($4.2 billion USD) in US debt on closing. The net cash purchase price was financed through: (i) $728 million ($560 million USD) related to the first instalment of convertible debentures represented by instalment receipts issued in 2015, $1.56 billion ($1.2 billion USD) fixed-to-floating subordinated notes, $500 million ($384 million USD) in Canadian long-term debt and $4.2 billion ($3.25 billion USD) in US long-term senior unsecured notes; (ii) available cash on hand; and (iii) drawings of $1.4 billion ($1.1 billion USD) on the Company's acquisition credit facility. Total proceeds of the debt, that were not otherwise required to complete the acquisition, have been used for general corporate purposes.

On August 2, 2016, the convertible debenture Final Instalment Date, Emera obtained the remaining two thirds of the convertible debenture instalments, for net proceeds of $1.4 billion. These funds were used to repay the Company's acquisition credit facility.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy's holdings include Tampa Electric, an integrated regulated electric utility in West Central Florida, PGS, a regulated gas distribution utility serving customers across Florida, and NMGC, a regulated gas distribution utility in New Mexico.

The majority of TECO Energy's operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission ("FERC"), Florida Public Service Commission, and New Mexico Public Regulation Commission ("NMPRC"), and are accounted for pursuant to USGAAP, including the accounting guidance for regulated operations. Except for unregulated long-term debt acquired and deferred taxes, preliminary fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values due to a market participant would not expect to recover any more or less than their net carrying value. Accordingly, assets acquired and liabilities assumed and pro-forma financial information do not reflect any adjustments related to these amounts.

The Acquisition is accounted for in accordance with the acquisition method of accounting. The excess of purchase price over estimated fair values of assets acquired and liabilities assumed has been recognized as goodwill at the acquisition date of July 1, 2016. The goodwill reflects the value paid for access to regulated assets, net income and cash flows in growth markets, opportunities for adjacency growth, long-term potential for enhanced access to capital as a result of increased scale and business diversity, and an improved earnings risk profile. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at July 1, 2016 based on their fair values, using the July 1, 2016 exchange rate of $1.00 USD = $1.3009 CAD.

	millions of Canadian dollars	
Purchase Consideration	$	8,447
Fair value assigned to net assets:		
Current assets (1)	$	619
Regulatory assets (including current portion)		624
Property, plant and equipment, net		10,023
Other long-term assets		71
Current liabilities		(748)
Assumed long-term debt (including current portion)		(5,409)
Regulatory liabilities (including current portion)		(1,117)
Deferred income taxes		(751)
Pension and post-retirement liabilities (including current portion)		(480)
Other long-term liabilities		(146)
	$	2,686
Cash and cash equivalents		38
Fair value of net assets acquired	$	2,724
Goodwill	$	**5,723**

(1) Includes accounts receivables with fair value of $334 million comprised of gross contract value of $337 million, and $3 million of contractual receivables not expected to be collected.

Goodwill has been preliminarily allocated to the TECO Energy reporting units and is subject to change as additional information is obtained through the purchase price allocation process.

millions of Canadian dollars Reporting Unit		Goodwill
Tampa Electric	**$**	**4,605**
Peoples Gas		**670**
New Mexico Gas		**448**
Goodwill	**$**	**5,723**

Goodwill is subject to an annual assessment for impairment at the reporting unit level. Adverse changes in assumptions could result in a material impairment of Emera's goodwill.

Acquisition Related Expenses

Acquisition related expenses totaled $156 million ($119 million after-tax) and $249 million ($179 million after-tax) for the three and nine months ended September 30, 2016 (2015 – $20 million after-tax). These costs have been recognized in the Condensed Consolidated Statements of Income as follows:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Operating revenues – regulated gas	**$ (10)**	$ -	**$ (10)**	$ -
Operating, maintenance, and general	**81**	30	**88**	30
Interest expense, net	**62**	1	**148**	1
Other income (expenses), net	**(3)**	3	**(3)**	3
Income tax expense (recovery)	**(37)**	(8)	**(70)**	(8)
Acquisition related costs	**$ 119**	$ 20	**$ 179**	$ 20

As part of the acquisition the Company has agreed to fund certain commitments in New Mexico. These commitments include contributions relating to economic development, donations, construction of an enlarged pipeline to the New Mexico/Mexico border, establishment of a matching fund to extend gas infrastructure in New Mexico and an annual customer bill reduction credit through June 30, 2018. In Q3 2016 Emera recognized $10 million in "Operating revenues - Regulated gas" and $30 million in "Operating, maintenance, and general" associated with these commitments for a total of $40 million ($23 million after-tax).

In addition to the New Mexico commitments, operating, maintenance, and general expenses includes acquisition related legal, accounting, banking and advisory fees and the accelerated vesting of outstanding stock-based compensation awards. Other income (expenses), net includes foreign exchange gains on acquisition related transactions. Interest expense, net includes interest incurred on the convertible debentures represented by instalment receipts and the acquisition credit facility issued for the purpose of financing the TECO Energy acquisition. In addition, it includes interest for the period between the issuance date and the acquisition date on acquisition-related debt and the Beneficial Conversion Feature discount expensed on conversion of the convertible debentures. Emera will not incur significant additional acquisition related expenses in Q4 2016.

Supplemental Pro Forma Data
The unaudited pro forma financial information below gives effect to the acquisition of TECO Energy as if the transaction had occurred at the beginning of 2016. This pro forma data is presented for information purposes only, and does not purport to be indicative of the results that would have occurred had the acquisition taken place at the beginning of 2016, nor is it indicative of the results that may be expected in future periods.

Pro forma net income attributable to common shareholders excludes all non-recurring acquisition-related expenses incurred by TECO Energy and Emera and includes adjustments for pro forma financing costs associated with the acquisition. In addition, net income from TECO Coal, a discontinued operation sold by TECO Energy in 2015 is excluded. After-tax adjustments increased pro forma net income attributable to common shareholders by $119 million and $66 million for the three and nine months ended September 30, 2016. The three and nine months ended September 30, 2015 after-tax adjustments were nil and a decrease of $22 million year-to-date.

Adjusted pro forma operating revenues increased by $10 million for both the three and nine month periods ended September 30, 2016, with no adjustment for 2015.

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Pro forma operating revenues	**$ 1,397**	$ 1,551	**$ 4,521**	$ 4,663
Pro forma net income attributable to common shareholders	**$ 24**	$ 104	**$ 329**	$ 338

5. 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 at September 30, 2016, Emera has six reportable segments, specifically:

- Emera Florida and New Mexico (includes TEC, consisting of two divisions: Tampa Electric and PGS, NMGC, their parent company TECO Energy, and TECO Finance, a wholly owned financing subsidiary of TECO Energy);
- NSPI;
- Emera Maine;
- Emera Caribbean (ECI and its subsidiaries including BLPC, Domlec, GBPC, and an equity investment in Lucelec);
- Emera Energy (Emera Energy Services, NEGG Facilities, Bayside Power, Brooklyn Energy and an equity investment in Bear Swamp; and
- Corporate and Other (Emera Utility Services, ENL, Emera Brunswick Pipeline, Corporate, other strategic investments and holding companies).

millions of Canadian dollars	Emera Florida and New Mexico (2)	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2016								
Operating revenues from external customers (1)	$ 959 $	292 $	77 $	115 $	(61) $	7 $	(3) $	1,386
Inter-segment revenues (1)	-	-	-	-	3	5	(7)	1
Total operating revenues	959	292	77	115	(58)	12	(10)	1,387
Net income (loss) attributable to common shareholders	2	15	17	24	(109)	(42)	(2)	(95)
For the nine months ended September 30, 2016								
Operating revenues from external customers (1)	959	1,004	222	314	231	34	(2)	2,762
Inter-segment revenues (1)	-	-	-	-	9	19	(26)	2
Total operating revenues	959	1,004	222	314	240	53	(28)	2,764
Net income (loss) attributable to common shareholders	109	96	36	92	(79)	12	(109)	157
As at September 30, 2016								
Total assets	11,554	4,684	1,496	1,255	1,429	7,602	(66)	27,954
For the three months ended September 30, 2015								
Operating revenues from external customers (1)	- $	305 $	79 $	119 $	120 $	18 $	- $	641
Inter-segment revenues (1)	-	-	-	3	4	7	(12)	2
Total operating revenues	-	305	79	122	124	25	(12)	643
Net income (loss) attributable to common shareholders	-	5	15	13	28	(26)	-	35
For the nine months ended September 30, 2015								
Operating revenues from external customers (1)	-	1,079	214	329	384	51	(1)	2,056
Inter-segment revenues (1)	-	-	-	8	10	18	(34)	2
Total operating revenues	-	1,079	214	337	394	69	(35)	2,058
Net income (loss) attributable to common shareholders	-	90	40	27	59	(11)	-	205
As at December 31, 2015							-	
Total assets	-	4,721	1,558	1,403	1,919	2,664	(226)	12,039

(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 that 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 which have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Financial results of Emera Florida and New Mexico are from July 1, 2016, the date of the acquisition.

6. REGULATED FUEL ADJUSTMENT MECHANISM AND FIXED COST DEFERRALS

NSPI's regulated fuel adjustment mechanism and fixed cost deferrals is recognized in the Condensed Consolidated Statement of Income and consisted of the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Regulated fuel adjustment mechanism (see chart below)	**$ 2**	$ 12	**$ 36**	$ 27
Application of non-fuel revenue	**4**	13	**12**	30
Regulated fixed cost deferral related to 2015 demand side management	**-**	(9)	**-**	(26)
	$ 6	$ 16	**$ 48**	$ 31

NSPI's Regulated Fuel Adjustment Mechanism

The regulated fuel adjustment mechanism ("FAM") in the Condensed Consolidated Statements of Income includes the effect of prudently incurred fuel for generation and purchased power and certain fuel related costs ("Fuel Costs") in both the current and preceding years, specifically, and as detailed in the table below:

- The difference between actual Fuel Costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities" on the Condensed Consolidated Balance Sheets; and
- The recovery from (rebate to) customers of under (over) recovered Fuel Costs from prior years.

The FAM is subject to an incentive, with NSPI retaining or absorbing 10 per cent of the over or under-recovered amount to a maximum of $5 million. The incentive was suspended for 2012 through 2015, as a result of UARB approved settlements and is in effect for 2016. The incentive is suspended as part of the *Electricity Plan Implementation (2015) Act (the "Electricity Plan Act")* in 2017 to 2019.

The regulated fuel adjustment mechanism on the Condensed Consolidated Statements of Income consisted of the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2016	2015	**2016**	2015
Over (under) recovery of current period Fuel Costs	**$ -**	$ 1	**$ 27**	$ (15)
Recovery from customers of prior years' Fuel Costs	**2**	11	**9**	42
Regulated fuel adjustment mechanism	**$ 2**	$ 12	**$ 36**	$ 27

The deferred FAM amounts are recognized as a "Regulatory asset" or "Regulatory liability" on the Condensed Consolidated Balance Sheets. The FAM regulatory liability balance of $80 million is disclosed in note 18 and includes associated interest recorded as "Interest expense, net" on the Condensed Consolidated Statements of Income.

In December 2015, the UARB approved NSPI's 2016 fuel rates and its recovery of prior period unrecovered Fuel Costs. The approved customer rates reset the base cost of fuel rates for 2016 and seeks to recover a total of $13 million of prior years' unrecovered Fuel Costs in 2016. The rates and recovery of these costs began January 1, 2016.

On December 18, 2015, the *Electricity Plan Act* was enacted by the Province of Nova Scotia. In accordance with the *Electricity Plan Act*, on March 7, 2016, NSPI filed with the UARB a three-year stability plan for Fuel Costs. On July 19, 2016, the UARB approved a consensus agreement between NSPI and customer representatives related to the stability plan for Fuel Costs for 2017 through 2019 which results in an average annual increase of 1.1 per cent for each of these three years. Subsequently, certain customer representatives requested changes to certain classes of rates. If the rates requested are approved by the UARB, the average annual rate increase of 1.1 per cent would increase to a 1.5 per cent average increase for each of these three years. A decision on the compliance filing is expected from the UARB in the fourth quarter of 2016.

The *Electricity Plan* Act directed that differences between actual Fuel Costs and amounts recovered from customers during 2016 are to be deferred to a FAM regulatory asset or liability and will recovered from or returned to customers in the 2017 to 2019 period. In addition it stated that differences between actual Fuel Costs and amounts recovered from customers through electricity rates during 2017 through 2019 will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers after 2019.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. The last audit completed was for 2012 and 2013. On August 12, 2016, the FAM audit results relating to fiscal 2014 and 2015 were publicly released and recommended one disallowance in the amount of $1 million. NSPI has issued its response to the audit report and disagrees with the recommended disallowance and a number of other findings in the report. A UARB regulatory process is in progress with a hearing scheduled for December 2016.

Application of Non-Fuel Revenues

The *Electricity Plan Act* directed NSPI to apply any non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. Further, any non-fuel revenues in excess of NSPI's approved range of return in 2017 through 2019 will be reserved and applied subsequent to 2019. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable wind projects is to be reserved to be applied to the FAM and used in the 2017 to 2019 period. The exception to this direction was to apply $4 million of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016.

For the three months ended September 30, 2016, NSPI applied $4 million (year-to-date $12 million) of non-fuel revenues to the FAM for the periods 2017 through 2019. This was as a result of applying the tax benefits associated with the South Canoe and Sable wind projects.

Fixed Cost Deferral Related to 2015 demand side management ("DSM")

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs were set for 2015 at $35 million and have been deferred as a regulatory asset and are recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of $102 million for the three year period of 2016 through 2018, which will be reduced by $7 million in 2017 as a result of underspend in 2015. The Electricity Plan Act has placed a cap of $34 million on the 2019 DSM spending. The 2016 annual DSM cost of $25 million will not be deferred and is charged to earnings.

The deferred DSM amounts from 2015 are recognized as a “Regulatory asset” on the Consolidated Balance Sheets. The DSM regulatory asset balance is detailed below and includes associated interest that is recorded as “Interest expense, net” on the Consolidated Statements of Income.

millions of Canadian dollars		**2016**
DSM regulatory asset – Balance as at January 1	**$**	**36**
Recovery of regulatory asset recorded as regulatory amortization		**(4)**
Interest on DSM balance		**2**
DSM regulatory asset – Balance as at September 30	**$**	**34**

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value as at September 30	Carrying Value as at December 31	Equity Income for the three months ended September 30		Equity Income for the nine months ended September 30		Percentage of Ownership
millions of Canadian dollars	**2016**	2015	**2016**	2015	**2016**	2015	**2016**
LIL (1)	**$ 326**	$ 208	**$ 6**	$ 3	**$ 16**	$ 6	62.7
NSPML	**272**	188	**6**	4	**15**	11	100.0
M&NP	**176**	189	**6**	5	**17**	17	12.9
Lucelec	**38**	39	**1**	1	**2**	2	19.1
Maine Electric Power Company Inc.	**7**	7	**-**	-	**-**	-	21.7
Cape Sharp Tidal Venture Ltd.	**5**	5	**-**	-	**-**	-	20.0
Chester Static Var Compensator	**5**	5	**-**	-	**-**	-	50.0
Maine Yankee Atomic Power Company	**-**	-	**-**	-	**-**	-	12.0
APUC (2)	**-**	504	**-**	4	**18**	19	4.7
Bear Swamp (3)	**-**	-	**4**	7	**11**	23	50.0
NWP	**-**	-	**-**	-	**-**	4	-
	$ 829	$ 1,145	**$ 23**	$ 24	**$ 79**	$ 82	

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

(2) On May 24, 2016, Emera completed the sale of 50.1 million common shares or 19.3 per cent of APUC's issued and outstanding common shares. This resulted in a pre-tax gain of $172 million (after-tax gain of $146 million), which was recorded in "Other income (expenses), net" in Q2 2016. On June 30, 2016, Emera exchanged 12.9 million of APUC subscription receipts and dividend equivalents into common shares. This resulted in a pre-tax gain of $63 million (after-tax gain of $53 million), which was recorded in "Other income (expenses), net" in Q2 2016. As a result of these transactions, Emera reclassified its investment in APUC from "Investments Subject to Significant Influence" to "Investment Securities" on the Condensed Consolidated Balance Sheets in Q2 2016.

(3) The investment balance in Bear Swamp is in a credit position primarily a result of a $179 million distribution received in Q4 2015. Bear Swamp's credit investment balance of $210 million (2015 - $225 million) is recorded in "Other long-term liabilities" on the Condensed Consolidated Balance Sheets.

Equity investments include a $13 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (see note 29). NSPML's summarized balance sheet is illustrated as follows:

As at millions of Canadian dollars		**September 30 2016**		December 31 2015
Balance Sheet				
Current assets	**$**	**448**	$	439
Property, plant and equipment		**1,041**		648
Non-current assets		**368**		566
Total assets		**1,857**		1,653
Current liabilities		**236**		130
Non-current liabilities		**1,349**		1,335
Equity		**272**		188
Total liabilities and equity	**$**	**1,857**	$	1,653

8. OTHER INCOME (EXPENSES), NET

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

For the millions of Canadian dollars		Three months ended September 30				Nine months ended September 30		
		2016		2015		**2016**		2015
Gain on sale of APUC common shares (note 7)	**$**	**-**	$	-	**$**	**172**	$	-
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC (note 7)		**-**		-		**63**		-
Gain on BLPC Self-Insurance Fund ("SIF") regulatory liability (1)		**-**		-		**53**		-
Allowance for equity funds used during construction		**10**		1		**12**		3
Investment income		**2**		-		**5**		1
Amortization of defeasance costs		**(2)**		(2)		**(5)**		(5)
Foreign exchange gains (losses)		**1**		4		**(3)**		6
Foreign exchange gains (losses) and mark-to-market adjustments related to the TECO Energy acquisition (2)		**(2)**		-		**(135)**		-
Gain on sale of NWP investment (3)		**-**		-		**-**		19
Other		**5**		-		**7**		2
	$	**14**	$	3	**$**	**169**	$	26

(1) In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $22 million USD. As a result, Emera reduced the SIF regulatory liability to $29 million and recorded a pre-tax gain of $53 million (after-tax gain of $43 million).
(2) Mark-to-market adjustments included in Emera's other income related to the effect of TECO Energy convertible debenture related USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures") for the TECO Energy acquisition.
(3) On January 25, 2015, Emera completed the sale of its 49 per cent interest in NWP. This resulted in a pre-tax gain of $19 million (after-tax gain of $12 million).

9. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars		Three months ended September 30			Nine months ended September 30
		2016	2015	**2016**	2015
Interest on debt	**$**	**166**	$ 49	**$ 276**	$ 145
Beneficial conversion feature (1)		**62**	-	**62**	-
Interest on Convertible Debentures (2)		**-**	1	**65**	1
Interest on acquisition credit facility related to the TECO Energy acquisition (note 4)		**3**	-	**11**	-
Allowance for borrowed funds used during construction		**(5)**	(1)	**(7)**	(4)
Other		**7**	-	**9**	-
	$	**233**	$ 49	**$ 416**	$ 142

(1) The Company recognized the difference between Emera's closing share price on the issuance date of the Convertible Debentures and their exercise price (the "Beneficial Conversion Feature") in June 2016 when the regulatory approval contingencies associated with the Acquisition were resolved. This $62 million ($43 million after-tax) non-cash discount was netted against the Convertible Debentures liability, and was to be amortized over the remaining term of the Convertible Debentures, or when the instrument was converted, whichever occurred first. In Q3 2016, 99.5 per cent of the Convertible Debentures were converted to equity, and as a result, Emera recognized an expense associated with the Beneficial Conversion Feature of $62 million for the three and nine month periods ended September 30, 2016.
(2) In 2015, Emera completed the sale of $2.185 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts. In Q2 2016 these costs included the make-whole interest payment of $21 million.

10. 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
		2016	2015	**2016**	2015
Income before provision for income taxes	**$**	**(120)**	$ 69	**$ 179**	$ 325
Statutory income tax rate		**31%**	31%	**31%**	31%
Income taxes, at statutory income tax rate		**(37)**	21	**56**	101
Non-taxable portion of gains on APUC transactions		**-**	-	**(36)**	-
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(8)**	(3)	**(35)**	(15)
Non-deductible portion of foreign exchange losses and mark-to-market adjustments related to the TECO Energy acquisition		**-**	-	**21**	-
Other		**1**	(6)	**(22)**	(14)
Income tax expense (recovery)	**$**	**(44)**	$ 12	**$ (16)**	$ 72
Effective income tax rate		**37%**	17%	**(9)%**	22%

The 2016 and 2015 statutory income tax rate of 31.0 per cent represents the combined Canadian federal and Nova Scotia provincial corporate income tax rates, which are the relevant tax jurisdictions for Emera.

The following reflects the composition of taxes on income from 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
		2016	2015	**2016**	2015
Income tax expense (recovery) – current	**$**	**12**	$ 4	**$ 35**	$ 64
Income tax expense (recovery) – deferred		**(56)**	8	**(51)**	8
Income tax expense (recovery)	**$**	**(44)**	$ 12	**$ (16)**	$ 72

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.

In Q2 2015, CRA commenced audit of NSPI's 2011 through 2013 taxation years. Should NSPI receive notices of reassessment for those years, and should the 2014 and 2015 taxation years be similarly reassessed, further payments will be required; however, the ultimate permissibility of these deductions is similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. The outcome of this process is not determinable at this time.

11. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars	
Balance, December 31, 2015	147.21	$	2,157
Conversion of Convertible Debentures	51.94		2,112
Issuance of common stock (1)	0.06		3
Issued for cash under Purchase Plans at market rate	1.56		72
Discount on shares purchased under Dividend Reinvestment Plan	-		(3)
Options exercised under senior management share option plan	0.56		16
Stock-based compensation	-		1
Balance, September 30, 2016	**201.33**	**$**	**4,358**

(1) In Q1 2016, Emera issued 0.06 million common shares to facilitate the creation and issuance of 0.2 million depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange.

Convertible Debentures

On September 28, 2015, to finance a portion of the acquisition of TECO Energy, Emera, through a direct wholly owned subsidiary (the "Selling Debentureholder") completed the sale of $1.9 billion aggregate principal amount of 4.0 per cent convertible unsecured subordinated debentures, represented by instalment receipts. On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures brought the aggregate proceeds of the Debenture Offering to $2.185 billion.

The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 (the "First Instalment") was paid on closing of the Debenture Offerings on September 28, 2015 and October 2, 2015, and the remaining $667 (the "Final Instalment") was payable on August 2, 2016 (the "Final Instalment Date"). Prior to the Final Instalment Date, the Debentures were represented by instalment receipts. The instalment receipts traded on the Toronto Stock Exchange ("TSX") from September 28, 2015 to August 2, 2016 under the symbol "EMA.IR". The Debentures will mature on September 29, 2025 and, as of the Final Instalment Date, bear interest at 0 per cent.

The proceeds of the first instalment and the over-allotment of the Debentures were $727.6 million ($681.4 million net of issue costs). The proceeds of the final instalment payment were $1.457 billion ($1.414 billion net of issue costs).

At the option of the holders, each fully paid Debenture is convertible into common shares of Emera at any time after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $41.85 per common share. This is a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures.

Final Instalment Notice was issued by Emera on June 29, 2016 with a payable date of August 2, 2016. As the Final Instalment Date occurred prior to the first anniversary of the closing of the Debenture Offering, holders of the convertible debentures who paid the final instalment by August 2, 2016 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including September 28, 2016. Recorded in the three months and nine months ended September 30, 2016 is nil and $65 million ($45 million after-tax) of interest expense related to the Convertible Debentures including the $21 million ($14 million after-tax) make-whole payment in Q2 2016 (note 9).

As at September 30, 2016, a total of 51.9 million common shares of the company were issued, representing conversion into common shares of more than 99.5 per cent of the Convertible Debentures. After the Final Instalment Date of August 2, 2016, debentures not converted may be redeemed by Emera at a price equal to their principal amount. At maturity, Emera has the right to pay the principal amount due in common shares to the debenture holders that have not converted, which will be valued at 95 per cent of the weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

12. 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	
	2016	2015	**2016**	2015
Numerator				
Net income attributable to common shareholders	**$ (95)**	$ 35	**$ 157**	$ 205
Convertible Debentures (1)	**-**	-	**0.2**	-
Diluted numerator	**(95)**	35	**157.2**	205
Denominator				
Weighted average shares of common stock outstanding	**181.7**	145.1	**159.4**	144.5
Weighted average deferred share units outstanding	**1.1**	0.9	**1.1**	0.9
Weighted average shares of common stock outstanding – basic	**182.8**	146.0	**160.5**	145.4
Stock-based compensation (1)	**-**	0.6	**0.6**	0.6
Dividend reinvestment plan (1)	**-**	0.5	**0.6**	0.5
Convertible Debentures (1)	**-**	-	**0.3**	-
Weighted average shares of common stock outstanding – diluted	**182.8**	147.1	**162.0**	146.5
Earnings per common share				
Basic	**$ (0.52)**	$ 0.24	**$ 0.98**	$ 1.41
Diluted	**$ (0.52)**	$ 0.24	**$ 0.97**	$ 1.40

(1) The following potential common shares were excluded from diluted EPS for the three months ended September 30, 2016 as the Company had a net loss for the quarter: 0.6 million related Stock-based compensation, 0.6 million related to Dividend reinvestment plan and 0.3 million related to the Company's 0.5% convertible debentures common shares that has a dilutive effect.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

millions of Canadian dollars	(Losses) gains on derivatives recognized as cash flow hedges	Net change in unrecognized pension and post-retirement benefit costs	Net change in net investment hedges	Net change in available-for-sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCI
For the nine months ended September 30, 2016						
Balance, January 1, 2016	$ (35)	$ (317)	$ -	$ -	$ 489	$ 137
Other comprehensive income (loss) before reclassifications	14	-	(13)	3	(117)	(113)
Amounts reclassified from accumulated other comprehensive income loss (gain)	7	29	-	(4)	-	32
Equity method reclassification adjustments	(7)	(3)	-	-	(36)	(46)
Net current period other comprehensive income (loss)	14	26	(13)	(1)	(153)	(127)
Other	-	-	-	-	(4)	(4)
Balance, September 30, 2016	$ (21)	$ (291)	$ (13)	$ (1)	$ 332	$ 6

millions of Canadian dollars	(Losses) gains on derivatives recognized as cash flow hedges	Net change in unrecognized pension and post-retirement benefit costs	Net change in net investment hedges	Net change in available-for-sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCI
For the nine months ended September 30, 2015						
Balance, January 1, 2015	$ (8)	$ (425)	$ -	$ 3	$ 82	$ (348)
Other comprehensive income (loss) before reclassifications	(26)	-	-	(4)	310	280
Amounts reclassified from accumulated other comprehensive income loss (gain)	4	46	-	-	-	50
Net current period other comprehensive income (loss)	(22)	46	-	(4)	310	330
Balance, September 30, 2015	$ (30)	$ (379)	$ -	$ (1)	$ 392	$ (18)

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 **2016**	2015	Nine months ended September 30 **2016**	2015
		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**	$ 1	**$ (2)**	$ (4)
Interest rate swaps	Income from equity investments	**-**	-	**1**	1
Foreign exchange forwards	Operating revenue – regulated	**3**	3	**8**	6
Total before tax		**4**	4	**7**	3
	Income tax expense (recovery)	**(1)**	(1)	**-**	1
Total net of tax		**$ 3**	$ 3	**$ 7**	$ 4
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses (gains)	OM&G	**$ 13**	$ 13	**$ 34**	$ 37
Past service costs (gains)	OM&G	**(2)**	(2)	**(7)**	(5)
Amounts reclassified into obligations	Pension and post-retirement liabilities	**-**	-	**-**	23
Total before tax		**11**	11	**27**	55
	Income tax expense (recovery)	**2**	-	**2**	(9)
Total net of tax		**$ 13**	$ 11	**$ 29**	$ 46
	Other income (expenses), net	**(4)**	-	**(4)**	-
Total before tax		**(4)**	-	**(4)**	-
	Income tax expense (recovery)	**-**	-	**-**	-
Total net of tax		**(4)**	-	**(4)**	-
Equity method reclassification adjustments					
	Investments subject to significant influence	**$ -**	-	**$ 54**	-
Total before tax		**-**	-	**54**	-
	Deferred income taxes	**-**	-	**(8)**	-
Total net of tax		**$ -**	-	**$ 46**	-
Total reclassifications out of AOCI, net of tax, for the period		**$ 12**	$ 14	**$ 78**	$ 50

14. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Customer accounts receivable – billed	**$ 601**	$ 406
Customer accounts receivable – unbilled	**204**	144
Total customer accounts receivable	**805**	550
Allowance for doubtful accounts	**(15)**	(12)
Customer accounts receivable, net	**790**	538
Other	**29**	40
	$ 819	$ 578

15. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars		**September 30 2016**		December 31 2015
Fuel	**$**	**252**	$	185
Materials		**204**		100
Emission credits (1)		**21**		29
	$	**477**	$	314

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

16. 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 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 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 2016**	December 31 2015	**September 30 2016**	December 31 2015
Current				
Cash flow hedges				
Power swaps	**$ 5**	$ 8	**$ 1**	$ 1
Foreign exchange forwards	**-**	-	**11**	14
	5	8	**12**	15
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**15**	-	**4**	12
Natural gas purchases and sales	**4**	2	**3**	1
Heavy fuel oil purchases	**2**	-	**8**	20
Foreign exchange forwards	**51**	85	**2**	10
Physical natural gas purchases and sales	**-**	2	**-**	-
	72	89	**17**	43
HFT derivatives				
Power swaps and physical contracts	**22**	151	**25**	119
Natural gas swaps, futures, forwards, physical contracts	**89**	-	**154**	359
Foreign exchange options	**-**	99	**-**	2
	111	250	**179**	480
Other derivatives				
Foreign exchange forwards	**-**	92	**-**	-
	-	92	**-**	-
Total gross current derivatives	**188**	439	**208**	538
Impact of master netting agreements with intent to settle net or simultaneously	**(79)**	(189)	**(79)**	(189)
Total current derivatives	**109**	250	**129**	349
Long-term				
Cash flow hedges				
Power swaps	**6**	12	**3**	4
Foreign exchange forwards	**-**	-	**11**	27
	6	12	**14**	31
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**49**	-	**1**	4
Natural gas purchases and sales	**1**	-	**3**	-
Heavy fuel oil purchases	**3**	-	**7**	17
Foreign exchange forwards	**54**	121	**-**	-
	107	121	**11**	21
HFT derivatives				
Power swaps and physical contracts	**13**	13	**26**	28
Natural gas swaps, futures, forwards and physical contracts	**27**	72	**135**	63
Foreign exchange options	**-**	1	**-**	1
	40	86	**161**	92
Other derivatives				
Interest rate swap	**-**	-	**3**	3
	-	-	**3**	3
Total gross long-term derivatives	**153**	219	**189**	147
Impact of master netting agreements with intent to settle net or simultaneously	**(32)**	(51)	**(32)**	(51)
Total long-term derivatives	**121**	168	**157**	96
Total derivatives	**$ 230**	$ 418	**$ 286**	$ 445

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 2016**	December 31 2015	**September 30 2016**	December 31 2015
HFT derivatives	**111**	240	**111**	240
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 111**	$ 240	**$ 111**	$ 240

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. Emera also enters into interest rate swaps to fix Bear Swamp's cost of debt. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCI, until the hedged transactions are recognized in income. The ineffective portion is recognized in income of the period. The amounts related to cash flow hedges recorded in income and AOCI consisted of the following:

For the millions of Canadian dollars			**2016**			Three months ended September 30 2015
	Power Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**(1)**	**-**	**-**	(1)	-	-
Realized gain (loss) in operating revenue – regulated	**-**	**-**	**(3)**	-	-	(3)
Total gains (losses) in net income	**$ (1)**	**$ -**	**$ (3)**	$ (1)	$ -	$ (3)

For the millions of Canadian dollars			**2016**			Nine months ended September 30 2015
	Power Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**2**	**-**	**-**	4	-	-
Realized gain (loss) in operating revenue – regulated	**-**	**-**	**(8)**	-	-	(6)
Realized gain (loss) in income from equity investments	**-**	**(1)**	**-**	-	(1)	-
Total gains (losses) in net income	**$ 2**	**$ (1)**	**$ (8)**	$ 4	$ (1)	$ (6)

As at millions of Canadian dollars			**September 30 2016**			December 31 2015
	Power Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ 2**	**$ (1)**	**$ (22)**	$ 4	$ (1)	$ (42)

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

As at September 30, 2016, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	**2016**	2017	2018	2019	2020
Foreign exchange forwards (USD) sales	**$ 13**	$ 53	$ 45	$ 30	$ 30
Foreign exchange forwards (EURO) purchases	**-**	3	-	-	-

Regulatory Deferral

As previously noted, Tampa Electric, PGS, NMGC, NSPI and GBPC defer gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exemption.

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

For the				Three months ended September 30		
millions of Canadian dollars			**2016**			2015
	Commodity swaps and forwards	**Physical natural gas 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	**$ (3)**	**$ -**	**$ (2)**	$ (15)	$ -	$ (3)
Unrealized gain (loss) in regulatory liabilities	**17**	**-**	**3**	-	2	72
Realized (gain) loss in regulatory assets	**1**	**-**	**5**	(1)	-	-
Realized (gain) loss in regulatory liabilities	**-**	**-**	**(4)**	-	-	-
Realized (gain) loss in inventory (1)	**-**	**-**	**(6)**	3	-	(11)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**4**	**-**	**(2)**	(2)	(3)	(5)
Total change in derivative instruments	**$ 19**	**$ -**	**$ (6)**	$ (15)	$ (1)	$ 53

(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			2016			Nine months ended September 30 2015
	Commodity swaps and forwards	**Physical natural gas 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	**$ 15**	**$ -**	**$ -**	$ (37)	$ -	$ (5)
Unrealized gain (loss) in regulatory liabilities	**66**	**(1)**	**(42)**	-	8	148
Realized (gain) loss in regulatory assets	**1**	**-**	**8**	-	-	-
Realized (gain) loss in regulatory liabilities	**-**	**-**	**(6)**	-	-	-
Realized (gain) loss in inventory (1)	**3**	**-**	**(39)**	6	-	(30)
Realized (gain) loss in property, plant and equipment	**-**	**-**	**-**	-	-	(1)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**15**	**-**	**(15)**	(5)	(5)	(14)
Total change in derivative instruments	**$ 100**	**$ (1)**	**$ (94)**	$ (36)	$ 3	$ 98

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period; hedging relationships that have been terminated or the hedged transaction is no longer probable.

Commodity Swaps and Forwards

As at September 30, 2016, 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:

	2016	2017-2020
millions	**Purchases**	Purchases
Coal (metric tonnes)	**-**	3
Natural Gas (Mmbtu)	**14**	39
Heavy fuel oil (bbls)	**1**	17

Foreign Exchange Swaps and Forwards

As at September 30, 2016, 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:

	2016	2017-2019
Fuel purchases exposure (millions of US dollars)	$ 51	$ 462
Weighted average rate	1.0500	1.0931
% of USD requirements	78%	84%

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	
	2016	2015	**2016**	2015
Power swaps and physical contracts in non-regulated operating revenues	**$ 4**	$ 3	**$ 1**	$ 7
Natural gas swaps, forwards, futures, physical contracts in non-regulated operating revenues	**(42)**	43	**219**	112
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for purchased power	**1**	1	**2**	(1)
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(4)**	(5)	**(2)**	(7)
Foreign exchange options in non-regulated operating revenue	**-**	(2)	**(1)**	(3)
	$ (41)	$ 40	**$ 219**	$ 108

As at September 30, 2016, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	**2016**	2017	2018	2019	2020
Natural gas purchases (Mmbtu)	**71**	171	68	57	48
Natural gas sales (Mmbtu)	**58**	115	15	12	8
Power purchases (MWh)	**-**	1	-	-	-
Power sales (MWh)	**1**	2	-	-	-
Foreign exchange options (USD)	**$ 4**	$ 13	$ 4	-	-

Other Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to cash flow hedges which documentation requirements have not been met:

For the millions of Canadian dollars		**2016**		Three months ended September 30 2015
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Unrealized gain (loss) in other income (expense)	**$ -**	**$ 102**	$ -	$ -
Realized gain (loss) in other income (expense)	**-**	**(87)**	-	-
Unrealized gain (loss) in interest expense, net	**-**	**-**	(2)	-
Total gains (losses) in net income	**$ -**	**$ 15**	$ **(2)**	$ **-**

For the millions of Canadian dollars		**2016**		Nine months ended September 30 2015
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Realized gain (loss) in other income (expense)	**-**	**(87)**	-	-
Unrealized gain (loss) in interest expense, net	**-**	**-**	(2)	-
Total gains (losses) in net income	**$ -**	**$ (87)**	$ **(2)**	$ **-**

As at September 30, 2016, 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.

During the three months ended September 30, 2016, $1,519 million foreign exchange forwards and swaps that were used to partially hedge proceeds for the TECO Energy acquisition settled.

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, recognizes 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, 2016, the Company had $97 million (December 31, 2015 - $83 million) in financial assets, considered to be past due, which have been outstanding for an average 65 days. The fair value of these financial assets is $82 million (December 31, 2015 - $72 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

Derivatives, as reflected on the Condensed Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables, net” and obligations to return cash collateral are recognized in “Accounts payable”.

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

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Cash collateral provided to others	**$ 63**	$ 107
Cash collateral received from others	**46**	29

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

As at September 30, 2016, the total fair value of these derivatives, in a liability position, was $286 million (December 31, 2015 – $445 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.

17. 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 16), 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, 2016
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 11	$ -	$ -	$ 11
	11	-	-	11
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	61	-	61
Natural gas purchases and sales	1	3	-	4
Heavy fuel oil purchases	2	3	1	6
Foreign exchange forwards	-	105	-	105
	3	172	1	176
HFT derivatives				
Power swaps and physical contracts	(5)	3	2	-
Natural gas swaps, futures, forwards, physical contracts and related transportation	1	9	33	43
	(4)	12	35	43
Total assets	10	184	36	230
Liabilities				
Cash flow hedges				
Power swaps	4	-	-	4
Foreign exchange forwards	-	22	-	22
	4	22	-	26
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	2	-	2
Heavy fuel oil purchases	-	15	-	15
Natural gas purchases and sales	3	3	-	6
Foreign exchange forwards		2	-	2
	3	22	-	25
HFT derivatives				
Power swaps and physical contracts	13	-	2	15
Natural gas swaps, futures, forwards and physical contracts	23	(14)	208	217
	36	(14)	210	232
Other derivatives				
Interest rate swap	-	3	-	3
	-	3	-	3
Total liabilities	43	33	210	286
Net assets (liabilities)	$ (33)	$ 151	$ (174)	$ (56)

As at				December 31, 2015
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 20	$ -	$ -	$ 20
	20	-	-	20
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	1	-	1
Foreign exchange forwards	-	207	-	207
Physical natural gas purchases and sales	-	-	2	2
	-	208	2	210
HFT derivatives				
Power swaps and physical contracts	38	1	(8)	31
Natural gas swaps, futures, forwards and physical contracts	-	8	57	65
	38	9	49	96
Other derivatives				
Foreign exchange forwards	-	92	-	92
	-	92	-	92
Total assets	58	309	51	418
Liabilities				
Cash flow hedges				
Power swaps	$ 5	$ -	$ -	$ 5
Foreign exchange forwards	-	41	-	41
	5	41	-	46
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	16	-	16
Natural gas purchases and sales	1	-	-	1
Heavy fuel oil purchases	-	37	-	37
Foreign exchange forwards	-	10	-	10
	1	63	-	64
HFT derivatives				
Power swaps and physical contracts	15	-	(2)	13
Foreign exchange options	-	4	-	4
Natural gas swaps, futures, forwards and physical contracts	14	22	279	315
	29	26	277	332
Other derivatives				
Interest rate swaps	-	3	-	3
	-	3	-	3
Total liabilities	35	133	277	445
Net assets (liabilities)	$ 23	$ 176	$ (226)	$ (27)

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 nine months ended September 30, 2016, there were no transfers between levels.

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2016 was as follows:

	Regulatory Deferral		*HFT Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Heavy fuel oil purchases	Power Swaps	Natural gas	Total
Balance, beginning of period	**$ -**	**$ 1**	**$ 3**	**$ 21**	**$ 25**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**(1)**	**12**	**11**
Balance, September 30, 2016	**$ -**	**$ 1**	**$ 2**	**$ 33**	**$ 36**

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2016 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 3**	**$ 103**	**$ 106**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(1)**	**105**	**104**
Balance, September 30, 2016	**$ 2**	**$ 208**	**$ 210**

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2016 was as follows:

	Regulatory Deferral		*HFT Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Heavy fuel oil purchases	Power	Natural gas	Total
Balance, beginning of period	**$ 2**	**$ -**	**$ (8)**	**$ 57**	**$ 51**
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	**(1)**	**-**	**-**	**-**	**(1)**
Unrealized gains (losses) included in regulatory assets or liabilities	**(1)**	**1**	**-**	**-**	**-**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**10**	**(24)**	**(14)**
Balance, September 30, 2016	**$ -**	**$ 1**	**$ 2**	**$ 33**	**$ 36**

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2016 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ (2)**	**$ 279**	**$ 277**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**4**	**(71)**	**(67)**
Balance, September 30, 2016	**$ 2**	**$ 208**	**$ 210**

Emera's Enterprise Risk Management group is responsible for valuation policies, processes and the measurement of fair value. Fair value accounting rules provide a three level hierarchy that prioritizes the inputs used to measure fair value. When possible, determining fair value is based primarily on observable market inputs in active markets.

Contracts with quoted prices available in active markets and exchanges for identical assets or liabilities are classified as level 1 in the hierarchy. For those contracts whereby pricing inputs are either directly or indirectly observable through markets, exchanges or third party sources, but do not qualify as level 1, are classified as level 2 in the hierarchy. For a level 3 classification, the processes and methods of measurement for third-party pricing information and illiquid markets are developed with input and using the market knowledge of the trading operations within Emera and its affiliates.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives includes 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, 2016**
millions of Canadian dollars		**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets						
Regulatory deferral – Financial heavy fuel oil purchases	$	1	Modelled pricing	Third-party pricing	$54.78 - $55.00	$54.89
				Probability of default	0.90%	0.90%
HFT derivatives – Power swaps and physical contracts		2	Modelled pricing	Third-party pricing	$19.70 - $76.94	$33.37
				Probability of default	0.00% - 0.01%	0.00%
				Discount rate	0.02% - 0.09%	0.03%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation		22	Modelled pricing	Third-party pricing	$0.83 - $8.85	$2.88
				Probability of default	0.00% - 0.06%	0.01%
				Discount rate	0.00% - 0.22%	0.03%
		11	Modelled pricing	Third-party pricing	$0.78 - $8.77	$3.12
				Basis adjustment	-0.11% - 0.61%	0.34%
				Probability of default	0.00% - 0.11%	0.01%
				Discount rate	0.00% - 0.06%	0.01%
Total assets		**36**				
Liabilities						
HFT derivatives – Power swaps and physical contracts	$	2	Modelled pricing	Third-party pricing	$19.70 - $76.94	$33.48
				Own credit risk	0.00% - 0.02%	0.01%
				Discount rate	0.09% - 0.02%	0.03%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		38	Modelled pricing	Third-party pricing	$0.83 - $8.85	$2.56
				Own credit risk	0.00% - 0.05%	0.00%
				Discount rate	0.00% - 0.07%	0.02%
		170	Modelled pricing	Third-party pricing	$0.78 - $8.74	$3.13
				Basis adjustment	-0.11% - 0.61%	0.13%
				Probability of default	0.00% - 0.22%	0.02%
				Discount rate	0.00% - 0.06%	0.01%
Total liabilities		**210**				
Net assets (liabilities)	**$**	**(174)**				

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						**September 30, 2016**
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Total**
Long-term debt (including current portion)	**$ 14,628**	**$ 16,234**	**$ 76**	**$ 15,551**	**$ 607**	**$ 16,234**

As at						December 31, 2015
millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
Long-term debt (including current portion)	$ 4,009	$ 4,487	$ -	$ 3,841	$ 646	$ 4,487

The fair values of long-term debt instruments, classified as level 1 in the fair value hierarchy, are valued using unadjusted quoted closing market prices that are traded in active markets.

Those classified as level 2 are valued either by using recent quoted market prices for the instrument where the instrument is not frequently traded, by using quoted closing market prices for similar issues that are frequently traded in an active market or by using quoted market prices and applying estimated credit spreads, provided by third-party pricing services, to the par value of the security.

Those classified as level 3 are valued by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality.

The Company has designated $1.2 billion United States dollar dominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations. A foreign currency loss of $13 million was recorded in Other Comprehensive Income for the nine months ended September 30, 2016 (2015 – nil). There was no ineffectiveness for the nine months ended September 30, 2016 (2015 – nil).

All other financial assets and liabilities, such as cash and cash equivalents, restricted cash, accounts receivable, short-term debt and accounts payable, are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

18. REGULATORY ASSETS AND LIABILITIES

A summary of the Company's regulatory assets and liabilities is provided below. For a detailed description of the nature of the Company's regulatory assets and liabilities, refer to Note 17 in Emera's 2015 annual audited consolidated financial statements.

The following outlines the regulatory environment of Emera Florida and New Mexico's regulated electric and gas utilities.

Tampa Electric and PGS are regulated separately by the FPSC. Tampa Electric is also subject to regulation by the FERC. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

Tampa Electric’s target regulated return on equity (“ROE”) range is 9.25 per cent to 11.25 per cent for 2016. Based on a Stipulation and Settlement Agreement in 2013, Tampa Electric will receive a revenue increase of $110 million USD effective January 1, 2017 or the date Tampa Electric’s Polk Power Station expansion goes into service, whichever is later. This agreement also provides that Tampa Electric’s allowed regulatory ROE would remain in place with a potential increase of the midpoint to 10.50 per cent from 10.25 per cent if U.S. Treasury bond yields exceed a specified threshold. This agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective no sooner than January 1, 2018), unless its earned ROE were to fall below 9.25 per cent (or 9.5 per cent if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25 per cent (or 11.5 per cent if the allowed ROE is increased as described above) any party to the agreement other than Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54 per cent from investor sources of capital.

PGS’s base rates are based upon an ROE of 10.75 per cent with a range between 9.75 per cent and 11.75 per cent.

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to their cost of providing service, plus an appropriate return on invested capital. As a condition of the NMPRC order (the “Order”) approving the acquisition of TECO Energy, NMGC will not seek an increase in base rates to be effective prior to December 31, 2017, and NMGC will continue to provide an annual bill reduction credit of $5 million ($4 million USD) through June 30, 2018.

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Regulatory assets		
Deferred income tax regulatory assets	**$ 613**	$ 431
Pension and post-retirement medical plan (1)	**399**	12
Environmental remediations (2)	**72**	**-**
Unamortized defeasance costs	**41**	46
2015 Demand side management deferral (note 6)	**34**	36
Stranded cost recovery	**27**	28
Deferrals related to derivative instruments	**26**	68
Debt basis adjustment (3)	**20**	**-**
Deferred bond refinancing costs (4)	**9**	**-**
Cost-recovery clauses (5)	**6**	-
Regulated fuel adjustment mechanism (note 6)	**-**	14
Other	**78**	64
	$ 1,325	$ 699
Current	**$ 68**	$ 94
Long-term	**1,257**	605
Total regulatory assets	**$ 1,325**	$ 699
Regulatory liabilities		
Accumulated reserve - cost of removal (6)	**977**	94
Deferrals related to derivative instruments	**173**	$ 209
Cost-recovery clauses (5)	**146**	**-**
Regulated fuel adjustment mechanism (note 6)	**80**	42
Transmission and delivery storm reserve (7)	**74**	**-**
Self-insurance fund (notes 8 and 22)	**29**	87
Deferred income tax regulatory liabilities	**25**	18
Bill reduction credit (8) (note 4)	**10**	**-**
Other	**26**	15
	$ 1,540	$ 465
Current	**$ 288**	$ 112
Long-term	**1,252**	353
Total regulatory liabilities	**$ 1,540**	$ **465**

(1) This asset is primarily related to the deferred pension and post-retirement benefits at Emera Florida and New Mexico. It is included in rate base and earns a rate of return as permitted by the FPSC or NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

(2) This asset is related to Tampa Electric costs associated with environmental remediation primarily at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is impacted by the timing of the expenditures related to remediation.

(3) This asset represents the difference between the fair value and pre-merger carrying amounts for NMGC's long-term debt on the date TECO Energy acquired NMGC. In accordance with purchase accounting standards, NMGC's long-term debt was valued at fair value on the Consolidated Balance Sheets. In accordance with the stipulation agreement with the NMPRC, an offsetting regulatory asset was recorded in order to eliminate the effects of purchase accounting on rate payers. The asset does not earn a return and is not included in the regulatory capital structure. It is amortized over the term of the related debt instrument.

(4) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.

(5) These assets and liabilities are related to FPSC and NMPRC recovery mechanisms. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year or next month in the case of purchased gas adjustments. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

(6) This liability is related to the non-ARO cost of removal ("COR") in the accumulated reserve for depreciation of Tampa Electric and NSPI. AROs are costs for legally required removal of property, plant and equipment. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as costs of removal are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service. Prior to July 1, 2016, NSPI presented cost of removal as a deduction in the carrying value of property, plant and equipment as part of accumulated depreciation.

(7) The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. Tampa Electric can petition the FPSC to seek recovery of restoration costs over a 12-month period or longer as determined by the FPSC, as well as replenish its reserve to the current level.

(8) This liability represents NMGC's stipulation agreement including a commitment to provide an annual bill reduction credit to customers, as part of Emera's acquisition of TECO Energy.

19. 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. Inter-company balances and inter-company 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. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. Below are transactions between Emera and its associated companies reported in the Condensed Consolidated Statements of Income:

For the millions of Canadian dollars			Three months ended September 30		Nine months ended September 30	
			2016	2015	**2016**	2015
	Nature of Service	**Presentation**				
Sales:						
APUC subsidiary (1)	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ -**	$ -	**$ 2**	$ 2
Purchases:						
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**1**	2	**2**	4
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**(6)**	(6)	**(21)**	(17)

(1) APUC subsidiary related party transactions includes transactions until May 24, 2016, when APUC ceased being a related party.

Operating revenue – non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate-regulated subsidiaries of Emera totaling $1 million for the three months ended September 30, 2016 (2015 $2 million) and $2 million for the nine months ended September 30, 2016 (2015 $2 million).

Amounts reported on Emera's Condensed Consolidated Balance Sheets due (to) from its equity investments are summarized in the following table:

As at millions of Canadian dollars	September 30 2016	December 31 2015
Due from related parties:		
NSPML – current	**$ 5**	$ 1
Subsidiary of APUC – current	**-**	1
M&NP – loan receivable – long-term	**3**	3
Due to related parties:		
M&NP – current	**2**	2
Net due from (to) related parties	**$ 6**	**$ 3**

All amounts are under normal interest and credit terms, except for a loan receivable from M&NP bearing interest at 1 per cent per annum maturing on November 30, 2019.

20. PROPERTY, PLANT AND EQUIPMENT

For a detailed description of the nature of the Company's property, plant and equipment refer to Note 20 in Emera's 2015 annual audited consolidated financial statements.

At September 30, 2016, $10,222 million of the total $16,658 million Property, plant and equipment, net of accumulated depreciation and amortization on the Consolidated Balance Sheet is attributable to the Emera Florida and New Mexico segment. This balance includes $1,203 million relating to the segment's construction work in progress.

21. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, Maine, Connecticut, Massachusetts, Rhode Island, New Mexico, Barbados, Dominica and Grand Bahama Island.

TECO Energy has three defined benefit pension plans:

- TECO Energy Group Retirement Plan. An ongoing qualified pension plan covering all employees of TECO Energy, Inc. and its affiliates. This plan is a pension equity plan funded solely by employer contributions. There are no employee contributions to this plan.
- TECO Energy Group Supplemental Executive Retirement Plan. An unqualified supplemental executive retirement plan covering certain officers elected by the previous TECO Energy Board of Directors. This plan was historically unfunded, but was funded as a result of Emera's acquisition of TECO Energy.
- TECO Energy Group Benefit Restoration Plan: An unfunded supplemental executive retirement plan effective January 1, 2016. The plan provides the benefits under the TECO Energy Group Retirement Plan formula that would otherwise be restricted as a result of the Internal Revenue Code.

In addition, there are two non-pension benefit plans:

- TECO Energy Post-retirement Health and Welfare Plan. This plan offers retirees under age 65 and their dependents a self-funded health reimbursement account ("HRA") medical plan identical to that offered to active TECO Energy employees. Retirees over the age of 65 are enrolled in a Medicare Advantage plan.
- New Mexico Gas Company Retiree Medical Plan: This plan offers retirees under age 65 and their dependents a self-funded HRA medical plan identical to that offered to active TECO Energy employees. Retirees over age 65 and their dependents receive a fixed subsidy with which they can purchase additional coverage through a medical supplement program. Dental benefits are provided to retirees and spouses. Plan assets are held in a trust.

The net periodic costs below that relate to TECO Energy reflect purchase accounting under which all unamortized bases have been eliminated and set up as a regulated asset or liability for TECO Energy's regulated companies. As a result of the acquisition, the market-related value of assets is reset to equal the market value of assets as at July 1, 2016.

Net periodic costs prior to the effects of capitalization for the Company consisted of the following:

For the millions of Canadian dollars		Three months ended September 30			Nine months ended September 30	
		2016		2015		**2016**		2015
Defined benefit pension plans								
Service cost	**$**	**12**	$	6	**$**	**23**	$	17
Interest cost		**24**		15		**54**		44
Expected return on plan assets		**(31)**		(16)		**(64)**		(48)
Current year amortization of:								
Actuarial losses (gains)		**10**		12		**31**		36
Past service costs (gains)		**-**		-		**(1)**		(1)
Regulated asset (liability)		**5**		-		**5**		**-**
Total defined benefit pension plans		**20**		17		**48**		48
Non-pension benefits plan								
Service cost		**1**		1		**3**		2
Interest cost		**4**		1		**5**		3
Expected return on plan assets		**(1)**		-		**(1)**		-
Current year amortization of:								
Actuarial losses (gains)		**1**		-		**2**		1
Past service costs (gains)		**(2)**		(2)		**(6)**		(4)
Total non-pension benefits plans		**3**		-		**3**		2
Total defined benefit plans	**$**	**23**	$	17	**$**	**51**	$	50

Emera's contributions related to these defined-benefit plans for the three months ended September 30, 2016 were $34 million (2015 – $5 million), and for the nine months ended September 30, 2016 were $47 million (2015 – $23 million).

In addition, the Company contributions related to the defined contribution plan for the three months ended September 30, 2016 were $3 million (2015 – $2 million), and for the nine months ended September 30, 2016 were $8 million (2015 – $7 million).

Additional Information on TECO Energy Plans

The following outlines the aggregate financial position for the five TECO Energy plans for the Projected Benefit Obligation ("PBO") or, for post-retirement plans, the Accumulated Post-retirement Benefit Obligation ("APBO") as at September 30, 2016:

	September 30, 2016			
millions of Canadian dollars		**Defined Benefit pension plans**		**Non-pension benefit plans**
PBO/APBO	$	1,044	$	278
Fair value of Plan Assets		866		30
Funded Status	$	(178)	$	(248)

The September 30, 2016 PBO/APBO were rolled forward from the January 1, 2016 valuation with the TECO Energy Group Retirement Plan liabilities increasing by 1% to reflect anticipated losses due to fewer deaths and more early retirements than expected.

Discount rates used to calculate TECO Energy plans' PBO/APBO and expenses disclosed in this note were based on the June 30, 2016 Mercer Select 100 yield curve and are as follows:
- TECO Energy Group Retirement Plan: 3.72%
- TECO Energy Group Supplemental Executive Retirement Plan: 2.64%
- TECO Energy Group Benefit Restoration Plan: 3.12%
- TECO Energy Postretirement Health and Welfare Plan: 3.85%
- New Mexico Gas Company Retiree Medical Plan: 3.85%

22. INVESTMENT SECURITIES

The Company has classified its investment securities as either available-for-sale or held-for-trading securities.

Available-for-sale securities

The available-for-sale securities consist primarily of debt and equity investments held in trust on behalf of BLPC's SIF for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. Any withdrawal of SIF Fund assets by the Company would be subject to existing regulations.

Third party risk advisors were engaged to support a detailed risk analysis, which was completed to quantify the prudent assessment of the risk to BLPC's transmission and distribution system from natural catastrophe. In June 2016 BLPC secured support from the Government of Barbados and the Trustees of the SIF to withdraw $65 million ($50 million USD) from the SIF (see note 8). The withdrawal was made in Q3 2016.

These investment securities include available-for-sale debt and equity investments related to Emera Reinsurance Limited, for captive insurance purposes.

Held-for-trading securities

The held-for-trading securities include Emera's 4.7 per cent investment in APUC (see note 7).

The investment securities discussed above are measured at fair value and classified in the fair value hierarchy as follows:

As at millions of Canadian dollars	NAV (1)	Level 1	Level 2	Level 3	September 30 2016
Available-for-sale					
Common shares	**$ -**	**$ 7**	**$ -**	**$ -**	**$ 7**
Corporate bonds, debentures, short and medium term notes	-	**-**	**11**	**-**	**11**
Other investments measured at NAV	**31**	**-**	**-**	**-**	**31**
	$ 31	**$ 7**	**11**	**$ -**	**$ 49**
Held-for-trading					
Common shares	-	**152**	**-**	**-**	**152**
	$ -	**$ 152**	**$ -**	**$ -**	**$ 152**
Total investment securities	**$ 31**	**$ 159**	**$ 11**	**$ -**	**$ 201**

As at millions of Canadian dollars	NAV (1)	Level 1	Level 2	Level 3	December 31 2015
Available-for-sale					
Common shares	$ -	$ 17	$ -	$ -	$ 17
Corporate bonds, debentures, short and medium term notes	-	-	34	-	34
Government bonds	-	-	12	-	12
Other investments measured at NAV	53	-	-	-	53
Total investment securities	$ 53	$ 17	$ 46	$ -	$ 116

(1) Certain investments are permitted to be measured at fair value using the net asset value ("NAV") per share under USGAAP accounting standards.

The change in available-for-sale securities is as follows:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Balance, beginning of the year	**$ 116**	$ 84
Additions	**12**	35
Disposals	**(71)**	(17)
	$ 57	$ 102
Change in fair value		
Unrealized (loss) gain recognized in income	**(4)**	-
Gain (loss) recognized in other comprehensive income during the period	**(4)**	14
	$ (8)	$ 14
Balance, end of the period	**$ 49**	$ 116

The change in held-for-trading securities is as follows:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Balance, beginning of the year	**$ -**	$ -
Additions (1)	**91**	-
Unrealized (loss) gain recognized in income	**61**	-
Balance, end of the period	**$ 152**	$ -

(1) Related to the reclassification of APUC common shares from "Investments Subject to Significant Influence" to "Investment Securities" in Q2 2016 (see note 7).

There were no impairment provisions for available-for-sale or held-for-trading investment securities for the three or nine months ended September 30, 2016 (2015 - nil).

The maturity profile of debt securities included in the available-for-sale securities is as follows:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Maturity within 1 year	**$ 1**	$ 20
Maturity in 1-5 years	**10**	26
	$ 11	$ 46

The maximum exposure to credit risk at the reporting date is the carrying value of the debt securities. None of these financial instruments are either past due or impaired.

23. GOODWILL

The change in goodwill for the nine months ended September 30 is due to the following:

millions of Canadian dollars	**2016**	2015
Balance, January 1	**$ 264**	$ 222
Acquisition of TECO Energy as at July 1, 2016 (note 4)	**5,723**	-
Change in foreign exchange rate	**34**	42
Balance, September 30	**$ 6,021**	$ 264

(1) No goodwill impairment was recorded for the nine months ended September 30, 2016 (2015 - nil). Emera assess' qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount during the fourth quarter of each year, and interim impairment tests are performed when impairment indicators are present.

24. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
Accrued charges	**$ 112**	$ 130
Accrued interest on long-term debt	**189**	44
Sales and other taxes payable	**10**	4
Accrued interest on convertible debentures represented by instalment receipts (note 9)	**-**	11
Emission credits obligations (1)	**6**	6
Dividend payable	**112**	-
Other	**16**	10
	$ 445	$ 205

(1) Throughout the three-year compliance period associated with the Regional Greenhouse Gas Initiative for carbon dioxide emissions, an obligation is recognized as gas is burned, measured at the cost to acquire credits for the related emissions. Emission credits are capitalized to inventory (note 15) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

25. LONG-TERM DEBT

Long-term debt as at September 30, including the debt assumed on the acquisition of TECO Energy, consisted of the following:

millions of Canadian dollars	Stated Interest Rate (1)	Maturity		2016		2015
Emera						
Bankers acceptances, LIBOR loans	Variable	2020	**$**	**85**	$	240
Notes (2)	2.96% to 6.75%	2016-2076		**2,549**		475
			$	**2,634**	$	715
NSPI						
Commercial paper	Variable	2020	**$**	**278**	$	370
Notes and debentures	3.61% to 9.75%	2019 - 2097		**2,060**		2,060
			$	**2,338**	$	2,430
Emera US Finance LP						
Notes (2)	2.15% to 4.75%	2019-2046	**$**	**4,263**		-
			$	**4,263**		-
Emera Maine						
LIBOR loans and demand loans	Variable	2019	**$**	**43**	$	32
Notes	3.61% to 10.25%	2017 - 2044		**340**		365
			$	**383**	$	397
EBP						
Bankers acceptances	3.08%	2019	**$**	**248**	$	249
			$	**248**	$	249
GBPC						
Notes	3.44% to 7.16%	2020 - 2023	**$**	**130**	$	145
			$	**130**	$	145
BLPC & ECI						
Notes	4.31% to 6.875%	2020 - 2028	**$**	**81**	$	89
			$	**81**	$	89
TECO Finance (3)						
Floating rate notes	Variable	2018		**328**		-
Notes	5.15% to 6.572%	2017-2020	**$**	**788**		-
			$	**1,116**		-
Tampa Electric						
Notes	1.5% - 6.55%	2018-2045	**$**	**2,518**		-
			$	**2,518**		-
PGS						
Notes	2.60% to 6.15%	2018-2045	**$**	**344**		-
			$	**344**		-
NMGC						
Notes	3.54% to 4.87%	2021-2026	**$**	**354**		-
			$	**354**		-
NMGI						
Notes	2.71% to 3.64%	2019-2024	**$**	**263**		-
			$	**263**		-
Adjustments						
FMV adjustment - TECO Energy acquisition (4)				**63**		-
Debt issuance costs				**(107)**		(16)
Amount due within one year				**(300)**		(274)
			$	**(344)**	$	(290)
Long-Term Debt			**$**	**14,328**	$	3,735

(1) The stated interest rate is the coupon rate for any long-term debt issuance.

(2) See below for details on the long-term debt related to the acquisition of TECO Energy.

(3) TECO Finance is a wholly owned subsidiary of TECO Energy. TECO Finance's sole purpose is to raise capital for TECO Energy's diversified businesses. TECO Energy is a full and unconditional guarantor of TECO Finance's securities, and no subsidiaries of TECO Energy guarantee TECO Finance's securities. A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

(4) On acquisition, Emera recorded a fair market value adjustment on the unregulated long-term debt in TECO Energy. The fair market value adjustment is amortized over the remaining term of the debt.

Recent Financing Activities

U.S. Notes

On June 16, 2016, Emera US Finance LP, a limited partnership financing subsidiary, wholly owned directly and indirectly by Emera, completed the issuance of $3.25 billion USD senior unsecured notes ("U.S. Notes"). The U.S. Notes are guaranteed by Emera and Emera US Holdings Inc., a wholly owned Emera subsidiary. The U.S. notes bear interest semi-annually, in arrears, on June 15 and December 15 of each year, commencing on December 15, 2016. The U.S. notes will not be listed on a securities exchange. The U.S. notes issued are described below:

$500 million USD three year, 2.15 per cent Notes due 2019
$750 million USD five year 2.70 per cent Notes due 2021
$750 million USD ten year 3.55 per cent Notes due 2026
$1.25 billion USD thirty year 4.75 per cent Notes due 2046

Hybrid Notes

On June 16, 2016, Emera completed the issuance of $1.2 billion USD unsecured, fixed-to-floating subordinated notes ("Hybrid Notes"). The Hybrid Notes will mature on June 15, 2076. Emera will pay interest on the Hybrid Notes at a fixed rate of 6.75 per cent per year in equal semi-annual instalments on June 15 and December 15 of each year until June 15, 2026. Starting on June 15, 2026, and on every quarter thereafter that the Hybrid Notes are outstanding until their maturity on June 15, 2076 (the "Interest Reset Date"), the interest rate on the Hybrid Notes will be reset.

Beginning on June 15, 2026, and on every Interest Reset Date until June 15, 2046, the Hybrid Notes will be reset at an interest rate of the three month LIBOR plus 5.44 per cent, payable in arrears. Beginning on June 15, 2046, and on every Interest Reset Date until June 15, 2076, the Hybrid Notes will be reset at an interest rate of the three-month LIBOR plus 6.19 per cent, payable in arrears.

Emera may elect, at its sole option, to defer the interest payable on the Hybrid Notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after June 15, 2026, Emera may, at its option, redeem the Hybrid Notes, at a redemption price equal to 100 per cent of the principal amount, together with accrued and unpaid interest.

Canadian Notes

On June 16, 2016, Emera completed the issuance of $500 million senior unsecured notes ("Canadian Notes"). The Canadian Notes were issued with a seven-year term to maturity and bear interest at a rate of 2.90 per cent. The notes will bear interest semi-annually in arrears on June 16 and December 16 of each year, commencing on December 16, 2016. The Canadian Notes will not be listed on a securities exchange.

The proceeds of the U.S. Notes, Hybrid Notes and Canadian Notes offerings were used to partially finance the purchase price for the Acquisition. Proceeds of the offerings, not otherwise required to complete the Acquisition, have been used for general corporate purposes.

As at September 30, 2016, the carrying value of the U.S., Hybrid, and Canadian Notes issued amounted to $6,261 million, and was recorded in "Long-term debt" on the Condensed Consolidated Balance Sheets.

NSPI

On April 28, 2016, NSPI increased its committed syndicated revolving bank line of credit to $600 million from $500 million. The increase will support ongoing business requirements and general corporate purposes.

On May 27, 2016, NSPI increased its commercial paper program to $500 million from $400 million, of which the full amount outstanding is backed by NSPI's operating credit facility referred to above. The amount of commercial paper issued results in an equal amount of its operating credit facility being considered drawn and unavailable.

26. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2016, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars		2016	2017	2018	2019	2020	Thereafter	Total
Purchased power (1)	$	76 $	247 $	222 $	203	200 $	2,453 $	3,401
Fuel and gas supply		212	458	146	95	28	21	960
Demand Side Management		7	32	40	5	-	-	84
Transportation (2)		131	408	337	292	253	1,622	3,043
Long-term service agreements (3)		27	64	49	60	40	227	467
Capital projects		136	46	1	-	-	-	183
Equity investment commitments (4)		332	178	-	200	-	-	710
Leases and other (5)		9	46	16	14	13	35	133
	$	930 $	1,479 $	811 $	869 $	534 $	4,358 $	8,981

(1) Annual requirement to purchase electricity production from independent power producers 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 in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to the Labrador Island Link Limited Partnership upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amounts as the projects advance through construction.

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

B. Legal Proceedings

Emera

Between September 16, 2015 and November 2, 2015, purported shareholders of TECO Energy filed 12 separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida or the United States District Court for the Middle District of Florida (the “Merger Litigation”). Each complaint alleges, among other things, that the Board of Directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and that Emera and/or Emera US Inc. aided and abetted such alleged breaches. The complaints sought to enjoin the merger pursuant to the acquisition agreement.

On November 17, 2015, TECO Energy, Emera, Emera US Inc. and the Board of Directors of TECO Energy entered into a memorandum of understanding with the shareholder plaintiffs to settle all of the Merger Litigation, subject to negotiation of a stipulation of settlement with the plaintiffs and to court approval. The memorandum of understanding provides for all claims against the defendants to be released in exchange for TECO Energy making certain additional disclosures to its shareholders related to the proposed merger, which have now been made.

On September 26, 2016, a hearing was held to gain preliminary approval of a negotiated stipulation of settlement. On September 30, 2016 the judge entered an order granting preliminary approval of the class action settlement and scheduling a final approval hearing for December 16, 2016.

There is no assurance that the court will approve the settlement.

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. On March 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified asserting 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 of the purchase of TECO Coal by Cambrian. While the outcome of such matter is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

TECO Guatemala Holdings ("TGH")

On December 19, 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 Fee Trade Agreement ("DR – CAFTA"), issued an award in the case ("the Award"). The ICSID Tribunal unanimously found in favor of TGH and awarded damages to TGH of approximately $21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus 2 per cent.

On April 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules.

Also on April 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the ICSID Tribunal's determination of the amount of TGH's damages.

On April 5, 2016, an ICSID ad hoc Committee issued a decision in favor of TGH in the annulment proceedings. In its decision, the ad hoc Committee unanimously dismissed Guatemala's application for annulment of the award and upheld the original $21 million USD award, plus interest. In addition, the ad hoc Committee granted TGH's application for partial annulment of the award, and ordered Guatemala to pay certain costs relating to the annulment proceedings. As a result, TGH has 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. Results to date do not reflect any benefit of this decision.

On Sept. 23, 2016, TGH filed a request for resubmission to arbitration. On Oct. 3, 2016, ICSID issued a notice of registration for TGH's request for resubmission, officially commencing the new arbitration and starting the time periods for constitution of the new tribunal.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its Peoples Gas 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, 2016, TEC has estimated its ultimate financial liability to be $44 million ($34 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, which are expected to be paid over many years, are not expected to have a significant impact on customer rates.

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

On September 30, 2011, a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users filed a complaint with the Federal Energy Regulatory Commission ("FERC") alleging that the 11.14 per cent base return on equity ("ROE") under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT") was unjust and unreasonable.

On June 19, 2014, the FERC issued an order in connection with this complaint that changed the methodology used to set the ROE and resulted in a lower base transmission ROE of 10.57 per cent and a lower total ROE (inclusive of incentive adders) of 11.74 per cent for the period of October 1, 2011 to December 31, 2012. The ROE was confirmed by FERC in two subsequent orders and has now been appealed to the U.S. Court of Appeals for the DC Circuit. The Court has decided to hold the appeal of this case in abeyance pending the outcome of the ENE Case and MA AG II Case discussed below.

On June 30, 2016, Emera Maine completed the processing of refunds to customers to reflect the 10.57 per cent ROE.

On December 27, 2012, a second group of consumer advocates, including Environment Northeast, filed a complaint with the FERC on similar grounds, arguing that the 11.14 per cent base ROE under the OATT was unjust and unreasonable ("the ENE Case"). This complaint applies to the period from January 1, 2013 to March 31, 2014. On July 31, 2014, a group of state commissions, state public advocates and end users filed a third complaint with the FERC on similar grounds ("the MA AG II Case") in relation to the period from July 31, 2014 to October 31, 2015. The ENE Case and MA AG II Case were subsequently consolidated by FERC into a single case.

On March 22, 2016, a FERC Administrative Law Judge ("ALJ") issued a recommended decision to FERC with respect to the consolidated cases. The recommendation for the ENE Case was a 9.59 per cent base ROE, with a 10.42 per cent maximum ROE, and the recommendation for the MA AG II Case was a 10.90 per cent base ROE, with a 12.19 per cent maximum ROE. The ALJ's recommended decision is not definitive and FERC has the ability to adjust the ALJ's recommended decision. A decision by FERC is not expected until Q4 2016.

On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"), a collection of thirteen municipal light departments, seeking to reduce the base ROE to 8.61 per cent and the maximum ROE to 11.24 per cent for the period April 29, 2016 to July 29, 2017.

Emera Maine has recorded a reserve of $5 million pre-tax ($4 million USD) (December 31, 2015 - $7 million or $5 million USD) for the ENE Case and MA AG II Case. The reserves recorded for these complaints 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 on a 10.57 per cent base and represents Emera Maine's best estimate of the probable outcome. No update has been made to the reserve as a result of the ALJ recommendation as it is pending approval by the FERC and is considered uncertain until that time. No reserve has been made as a result of the EMCOS complaint, as the outcome is considered uncertain.

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. Environment

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. Emera estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations will be approximately $37 million during fiscal 2016 and are estimated to be $232 million from 2017 through 2020. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 26A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions.

Emera Florida and New Mexico

Tampa Electric operates fossil fuel burning power plants with air emissions regulated by the Clean Air Act and material Clean Water Act implications and impacts by federal and state legislative initiatives. Tampa Electric Company, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites, and, through its PGS divisions, for certain former manufactured gas plant sites. NMG has not been designated as a PRP and has no former manufactured gas plant sites. Tampa Electric has achieved the emission-reduction levels called for in Phase I and Phase II of Clean Air Interstate Rule. Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the environmental cost recovery clause ("ECRC"). If approved as prudent, the cost required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but it is uncertain if the FPSC would grant such recovery.

NSPI

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters, primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

In June 2016, the Federal government announced a formal review process for several Acts and processes including the Canadian Environmental Assessment Act ("CEAA") and process, the National Energy Board ("NEB") processes, the Fisheries Act and the Navigation Protection Act. The Company will participate in the consultation process.

In November 2014, the Government of Canada and the Province of Nova Scotia entered into a greenhouse gas emission regulations equivalency agreement, which allows NSPI to achieve compliance with federal greenhouse gas emissions regulations by meeting provincial legislative and regulatory requirements as they were deemed to be equivalent. In March 2016, the Prime Minister of Canada met with provincial premiers to begin the development of a pan-Canadian plan to reduce greenhouse gases. They issued a joint statement; the Vancouver Declaration, in which First Ministers agreed to work together on a pan-Canadian framework on clean growth and climate change, and implement it by early 2017. In October 2016, the Prime Minister announced that there would be a national price on carbon, implemented by 2018 through either a carbon tax or a cap and trade system, applicable in each province except those which enact their own comparable carbon pricing mechanism by that time. NSPI is providing input to the process through the Nova Scotia government, the Federal government and directly through submission of a discussion paper. The impact of the announced carbon pricing system on Emera's Canadian operating companies, and the effect, if any, on the existing equivalency agreement is uncertain at this time.

Conformance with legislative and NSPI internal requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to September 30, 2016.

Polychlorinated Biphenyl Equipment

In response to the Canadian Environmental Protection Act 1999, 2008 Polychlorinated Biphenyl ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil-filled electrical equipment on its system that fall under the 2008 PCB Regulations Standard by the end of 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be $46 million and, as at September 30, 2016, approximately $27 million (December 31, 2015 – $20 million) has been spent to date. NSPI has recognized an ARO on the balance sheet of $14 million as at September 30, 2016 (December 31, 2015 – $15 million) associated with the PCB phase-out program.

Emera Energy Emissions

The NEGG Facilities are subject to the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions and the Acid Rain Program for sulphur dioxide emissions. The NEGG Facilities emit approximately two million tons of carbon dioxide per year. The amount of sulphur dioxide emitted is not considered significant. Changes to these emissions programs could adversely impact financial and operational performance.

D. Principal Risks and Uncertainties

In this section, Emera describes some of the principal risks management believes could materially affect Emera's business, revenues, operating income, net income, net asset or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise, or risks not currently considered material may become material in the future.

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.

Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments in a timely manner. As cost-of-service utilities with an obligation to serve, Tampa Electric, Peoples Gas, New Mexico, NSPI, Emera Maine, BLPC, GBPC and Domlec must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon the respective regulator's approval of the recovery in adjustments to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. The commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by significant shifts in government policy and changes in governments. Emera has certain investments subject to significant influence that are subject to regulatory risk and include: NSPML, LIL M&NP and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these subsidiaries and their respective regulators determine whether to allow recovery and to adjust rates based upon the subsidiaries' evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

On April 13, 2016, in association with a distribution rate application, the Maine Public Utilities Commission ordered an audit of Emera Maine's implementation of its new customer information system and customer service performance, including billing and reliability. The audit commenced in Q2 2016 and a report was issued on August 8, 2016 recommending a disallowance of approximately $2 million USD. Emera Maine disputes the audit findings and has not recorded an allowance. An estimated range of outcomes cannot be reliably estimated at this time. A decision on the case is expected in Q4 2016.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters; primarily related to its utility operations. This includes laws setting greenhouse gas emissions standards and air emissions standards. Emera is also subject to laws regarding the generation, storage, transportation, use and disposal of hazardous substances and materials.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera.

New emission reductions requirements for the utilities sector are being established by governments in Canada and the United States. Changes to greenhouse gas emissions standards and air emissions standards could adversely affect Emera's operations and financial performance. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of achieving full compliance with applicable laws, legislation and company policies and standards. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance with such laws, policies and standards.

Commercial Relationships

The Company is exposed to commercial relationship risk in respect of its reliance on certain key partners, supplies and customers. The company manages its commercial relationship risk by monitoring credit risk, and monitoring of significant developments with its customers, partners and suppliers.

ENL

Emera and Nalcor Energy executed agreements pertaining to the development and transmission of hydroelectric power from Muskrat Falls in Labrador to the island of Newfoundland, the Province of Nova Scotia and through to New England. In exchange for the Company's investment in the Maritime Link Project, estimated to be approximately $1.56 billion, Nalcor has agreed to provide 20 per cent of the output of the Muskrat Falls generating station.

Interest Rate Risk

The Company utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. The Company 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 the Company's regulated subsidiaries, the cost of debt is generally passed through to ratepayers. While regulatory ROE rates will generally and indirectly follow the direction of interest rates, regulatory ROE's are likely to fall in times of reducing interest rates and raise 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 initiatives.

Commodity Prices and Foreign Exchange Rate Fluctuations

A substantial amount of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. 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. In addition, the adoption and implementation of FAMs in certain subsidiaries has further helped manage this risk. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs.

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases and USD revenue streams.

In addition, during October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the final instalment of the Debenture Offering of the TECO Energy acquisition of $1.457 billion. These foreign exchange forward contracts were economic hedges and did not qualify for hedge accounting. Therefore, all mark-to-market gains and losses have been recognized in net income for the period.

The operations of TECO Energy are conducted in US dollars. Following the acquisition, the consolidated net income of Emera will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar.

E. Guarantees and Letters of Credit

There were no material changes in Emera's guarantees and letters of credit since December 31, 2015.

TECO Energy has letters of indemnity related to TECO Coal, which totaled $112 million ($85 million USD) at September 30, 2016. These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety.

The amounts outlined represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies. TECO Coal was sold on September 21, 2015 to Cambrian. Pursuant to the sales agreement, Cambrian is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective. At the date of sale in September 2015, the letters of indemnity guaranteed $123 million ($94 million USD).

The company is working with Cambrian on the process to replace the bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

27. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars	**September 30 2016**	December 31 2015
ICDU	**$ 52**	$ 52
Preferred shares of GBPC	**34**	34
Domlec (1)	**24**	48
	$ 110	$ 134

(1) On March 22, 2016, an indirect wholly-owned subsidiary of Emera acquired 0.7 million ECI shares (which owns 51.9 per cent share of Domlec), increasing Emera's ownership interest from 95.5 to 100 per cent.

28. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Nine months ended September 30 **2016**	 2015
Changes in non-cash working capital:		
Receivables, net	**$ 76**	$ 95
Income taxes receivable	**(32)**	(17)
Inventory	**76**	22
Prepaid expenses	**(25)**	(10)
Due from related party	**(4)**	2
Other current assets	**11**	(1)
Accounts payable	**60**	(72)
Income taxes payable	**16**	(28)
Other current liabilities	**74**	(20)
Total non-cash working capital	**252**	(29)
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 63**	$ 55
Beneficial Conversion Feature of the convertible debentures	**$ 43**	$ -

29. VARIABLE INTEREST ENTITIES

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

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

For the three and nine months ended September 30, 2016, the Company has identified the following significant VIEs:

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, critical milestones were achieved and 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 Project. Thus, Emera records the Maritime Link Project 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 (notes 22 and 18). Emera's consolidated VIE in the SIF is recorded as an "Investment securities" and "Restricted cash".

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 significant unconsolidated VIEs:

As at	**September 30, 2016**		December 31, 2015	
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)	**$ 272**	**$ 653**	$ 188	$ 1,007

30. 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.

31. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company’s evaluation of events occurring subsequent to the balance sheet date through November 7, 2016, the date the financial statements were issued.

32. SUPPLEMENTAL FINANCIAL INFORMATION

On June 16, 2016, Emera US Finance LP, (in such capacity, the “Issuer”), issued $3.25 billion USD senior unsecured notes (“U.S. Notes”). The U.S Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera (in such capacity, the “Parent Company”) and EUSHI (in such capacity, the “Guarantor Subsidiaries”). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP.

The following condensed consolidated financial statements present the results of operations, financial position and cash flows of the Parent Company, Subsidiary Issuer, Guarantor Subsidiaries and all other Non-guarantor Subsidiaries independently and on a consolidated basis.

Our guarantors were not determined using geographic, service line or other similar criteria, and as a result, the “Parent”, “Subsidiary Issuer”, “Guarantor Subsidiaries” and “Non-guarantor Subsidiaries” columns each include portions of our domestic and international operations. Accordingly, this basis of presentation is not intended to present our financial condition, results of operations or cash flows for any purpose other than to comply with the specific requirements for guarantor reporting.

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)
For the three months ended September 30, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues						
Regulated electric	$ -	$ -	$ 841	$ 406	$ (1)	**$ 1,246**
Regulated gas	-	-	181	11	-	**192**
Non-regulated	-	-	78	(122)	(7)	**(51)**
Total operating revenues	-	-	1,100	295	(8)	**1,387**
Operating expenses						
Regulated fuel for generation and purchased power	-	-	297	159	-	**456**
Regulated cost of natural gas	-	-	69	-	-	**69**
Regulated fuel adjustment mechanism and fixed cost deferrals	-	-	-	6	-	**6**
Non-regulated fuel for generation and purchased power	-	-	46	18	-	**64**
Non-regulated direct costs	-	-	-	10	(6)	**4**
Operating, maintenance and general	9	-	313	103	(2)	**423**
Provincial, state and municipal taxes	-	-	74	11	-	**85**
Depreciation and amortization	-	-	138	66	-	**204**
Total operating expenses	9	-	937	373	(8)	**1,311**
Income (loss) from operations	(9)	-	163	(78)	-	**76**
Income (loss) from equity investments in subsidiaries	(40)	-	-	-	40	**-**
Income from equity investments	-	-	-	23	-	**23**
Intercompany income (expenses), net	49	50	(51)	(43)	(5)	**-**
Other income (expenses), net	(1)	-	11	4	-	**14**
Interest expense, net	103	39	55	36	-	**233**
Income (loss) before provision for income taxes	(104)	11	68	(130)	35	**(120)**
Income tax expense (recovery)	(23)	4	34	(59)	-	**(44)**
Net income (loss)	(81)	7	34	(71)	35	**(76)**
Non-controlling interest in subsidiaries	-	-	-	3	2	**5**
Net income (loss) of Emera Incorporated	(81)	7	34	(74)	33	**(81)**
Preferred stock dividends	14	-	5	2	(7)	**14**
Net income (loss) attributable to common shareholders	$ (95)	$ 7	$ 29	$ (76)	$ 40	**$ (95)**
Comprehensive income (loss) of Emera Incorporated	$ (26)	$ 8	$ 80	$ (56)	$ (32)	**$ (26)**

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)
For the three months ended September 30, 2015

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues						
Regulated electric	$ -	$ -	$ 78	$ 425	$ -	**$ 503**
Regulated gas	-	-	-	13	-	**13**
Non-regulated	-	-	99	39	(11)	**127**
Total operating revenues	-	-	177	477	(11)	**643**
Operating expenses						
Regulated fuel for generation and purchased power	-	-	20	166	-	**186**
Regulated fuel adjustment mechanism and fixed cost deferrals	-	-	-	16	-	**16**
Non-regulated fuel for generation and purchased power	-	-	44	13	-	**57**
Non-regulated direct costs	-	-	-	14	(9)	**5**
Operating, maintenance and general	19	-	52	117	(2)	**186**
Provincial, state and municipal taxes	-	-	6	11	-	**17**
Depreciation and amortization	-	-	20	65	-	**85**
Total operating expenses	19	-	142	402	(11)	**552**
Income (loss) from operations	(19)	-	35	75	-	**91**
Income (loss) from equity investments in subsidiaries	36	-	-	-	(36)	**-**
Income from equity investments	4	-	-	20	-	**24**
Intercompany income (expenses), net	34	-	(1)	(28)	(5)	**-**
Other income, net	-	-	1	2	-	**3**
Interest expense, net	6	-	5	38	-	**49**
Income (loss) before provision for income taxes	49	-	30	31	(41)	**69**
Income tax expense	-	-	11	1	-	**12**
Net income (loss)	49	-	19	30	(41)	**57**
Non-controlling interest in subsidiaries	-	-	-	4	3	**7**
Net income (loss) of Emera Incorporated	49	-	19	26	(44)	**50**
Preferred stock dividends	14	-	3	6	(8)	**15**
Net income (loss) attributable to common shareholders	$ 35	$ -	$ 16	$ 20	$ (36)	**$ 35**
Comprehensive income (loss) of Emera Incorporated	$ 195	$ -	$ 111	$ 81	$ (192)	**$ 195**

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)
For the nine months ended September 30, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues						
Regulated electric	$ -	$ -	$ 985	$ 1,318	$ (2)	**$ 2,301**
Regulated gas	-	-	181	36	-	**217**
Non-regulated	-	-	291	(20)	(25)	**246**
Total operating revenues	-	-	1,457	1,334	(27)	**2,764**
Operating expenses						
Regulated fuel for generation and purchased power	-	-	333	477	-	**810**
Regulated cost of natural gas	-	-	69	-	-	**69**
Regulated fuel adjustment mechanism and fixed cost deferrals	-	-	-	48	-	**48**
Non-regulated fuel for generation and purchased power	-	-	200	45	(2)	**243**
Non-regulated direct costs	-	-	-	25	(18)	**7**
Operating, maintenance and general	31	-	380	342	(7)	**746**
Provincial, state and municipal taxes	-	-	85	33	-	**118**
Depreciation and amortization	2	-	182	192	-	**376**
Total operating expenses	33	-	1,249	1,162	(27)	**2,417**
Income (loss) from operations	(33)	-	208	172	-	**347**
Income (loss) from equity investments in subsidiaries	83	-	-	-	(83)	**-**
Income from equity investments	18	-	-	61	-	**79**
Intercompany income (expenses), net	155	50	(54)	(128)	(23)	**-**
Other income (expenses), net	145	-	11	13	-	**169**
Interest expense, net	189	46	71	110	-	**416**
Income (loss) before provision for income taxes	179	4	94	8	(106)	**179**
Income tax expense (recovery)	(6)	2	39	(51)	-	**(16)**
Net income (loss)	185	2	55	59	(106)	**195**
Non-controlling interest in subsidiaries	-	-	-	6	4	**10**
Net income (loss) of Emera Incorporated	185	2	55	53	(110)	**185**
Preferred stock dividends	28	-	16	11	(27)	**28**
Net income (loss) attributable to common shareholders	$ 157	$ 2	$ 39	$ 42	$ (83)	**$ 157**
Comprehensive income (loss) of Emera Incorporated	$ 59	$ 6	$ 17	$ 30	$ (53)	**$ 59**

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)
For the nine months ended September 30, 2015

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues						
Regulated electric	$ -	$ -	$ 213	$ 1,409	$ (2)	**$ 1,620**
Regulated gas	-	-	-	39	-	**39**
Non-regulated	-	-	319	113	(33)	**399**
Total operating revenues	-	-	532	1,561	(35)	**2,058**
Operating expenses						
Regulated fuel for generation and purchased power	-	-	52	563	-	**615**
Regulated fuel adjustment mechanism and fixed cost deferrals	-	-	-	31	-	**31**
Non-regulated fuel for generation and purchased power	-	-	204	45	(4)	**245**
Non-regulated direct costs	-	-	-	40	(25)	**15**
Operating, maintenance and general	39	-	99	361	(6)	**493**
Provincial, state and municipal taxes	-	-	16	32	-	**48**
Depreciation and amortization	-	-	58	194	-	**252**
Total operating expenses	39	-	429	1,266	(35)	**1,699**
Income (loss) from operations	(39)	-	103	295	-	**359**
Income (loss) from equity investments in subsidiaries	173	-	-	-	(173)	**-**
Income from equity investments	19	-	5	58	-	**82**
Intercompany income (expenses), net	109	-	(7)	(81)	(21)	**-**
Other income (expenses), net	1	-	23	2	-	**26**
Interest expense, net	19	-	14	109	-	**142**
Income (loss) before provision for income taxes	244	-	110	165	(194)	**325**
Income tax expense (recovery)	9	-	36	27	-	**72**
Net income (loss)	235	-	74	138	(194)	**253**
Non-controlling interest in subsidiaries	-	-	-	9	9	**18**
Net income (loss) of Emera Incorporated	235	-	74	129	(203)	**235**
Preferred stock dividends	30	-	11	19	(30)	**30**
Net income (loss) attributable to common shareholders	$ 205	$ -	$ 63	$ 110	$ (173)	**$ 205**
Comprehensive income (loss) of Emera Incorporated	$ 565	$ -	$ 263	$ 249	$ (512)	**$ 565**

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)
As at September 30, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Assets						
Current assets						
Cash and cash equivalents	$ -	$ 12	$ 130	$ 277	$ (4)	**$ 415**
Restricted cash	-	-	1	16	-	**17**
Receivables, net	3	-	411	405	-	**819**
Intercompany receivable	219	50	2	57	(328)	**-**
Income taxes receivable	-	-	6	31	-	**37**
Inventory	-	-	261	216	-	**477**
Derivative instruments	12	-	14	95	(12)	**109**
Regulatory assets	-	-	34	34	-	**68**
Prepaid expenses	1	-	38	29	-	**68**
Due from related parties	1	-	-	4	-	**5**
Other current assets	2	-	2	38	-	**42**
Total current assets	238	62	899	1,202	(344)	**2,057**
Property, plant and equipment, net of accumulated depreciation	15	-	12,155	4,488	-	**16,658**
Other assets						
Income taxes receivable	-	-	-	48	-	**48**
Deferred income taxes	23	-	9	47	16	**95**
Derivative instruments	16	-	-	120	(15)	**121**
Pension and post-retirement asset	-	-	-	9	-	**9**
Regulatory assets	-	-	701	556	-	**1,257**
Net investment in direct financing lease	-	-	10	476	-	**486**
Investments in subsidiaries accounted for using the equity method	8,179	-	-	-	(8,179)	**-**
Investments subject to significant influence	5	-	12	812	-	**829**
Investment securities	152	-	-	49		**201**
Goodwill	-	-	5,920	101	-	**6,021**
Due from related parties	-	-	-	3	-	**3**
Intercompany notes receivable	3,052	4,452	-	2,782	(10,286)	**-**
Other investments - intercompany	-	-	-	2,270	(2,270)	**-**
Other long-term assets	14	-	84	71	-	**169**
Total other assets	11,441	4,452	6,736	7,344	(20,734)	**9,239**
Total assets	$ 11,694	$ 4,514	$ 19,790	$ 13,034	$ (21,078)	**$ 27,954**

Emera Incorporated
Condensed Consolidated Balance Sheets – (Unaudited) Continued
As at September 30, 2016

As at millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Liabilities and Equity						
Current liabilities						
Short-term debt	$ 4	$ -	$ 801	$ (1)	$ (4)	**$ 800**
Current portion of long-term debt	250	-	32	18	-	**300**
Accounts payable	43	-	713	346	-	**1,102**
Intercompany payable	8	-	126	186	(320)	**-**
Income taxes payable	-	2	-	13	-	**15**
Derivative instruments	12	-	11	118	(12)	**129**
Regulatory liabilities	-	-	202	86	-	**288**
Pension and post-retirement liabilities	-	-	49	7	-	**56**
Due to related party	-	-	-	2	-	**2**
Other current liabilities	196	46	99	104	-	**445**
Total current liabilities	513	48	2,033	879	(336)	**3,137**
Long-term liabilities						
Long-term debt	2,351	4,219	4,991	2,767	-	**14,328**
Intercompany long-term debt	2,631	-	4,601	3,053	(10,285)	**-**
Deferred income taxes	-	-	1,090	464	16	**1,570**
Convertible debentures	10	-	-	-	-	**10**
Derivative instruments	15	-	-	157	(15)	**157**
Regulatory liabilities	-	-	948	304	-	**1,252**
Asset retirement obligations	-	-	9	111	-	**120**
Pension and post-retirement liabilities	14	-	465	194	-	**673**
Other long-term liabilities	6	-	223	214	-	**443**
Total long-term liabilities	5,027	4,219	12,327	7,264	(10,284)	**18,553**
Equity						
Common stock	4,358	242	4,177	3,996	(8,415)	**4,358**
Cumulative preferred stock	709	-	620	271	(891)	**709**
Contributed surplus	75	-	45	140	(185)	**75**
Accumulated other comprehensive income (loss)	6	3	207	(190)	(20)	**6**
Retained earnings	1,006	2	381	598	(981)	**1,006**
Total Emera Incorporated equity	6,154	247	5,430	4,815	(10,492)	**6,154**
Non-controlling interest in subsidiaries	-	-	-	76	34	**110**
Total equity	6,154	247	5,430	4,891	(10,458)	**6,264**
Total liabilities and equity	$ 11,694	$ 4,514	$ 19,790	$ 13,034	$ (21,078)	**$ 27,954**

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)
As at December 31, 2015

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Assets						
Current assets						
Cash and cash equivalents	$ -	$ -	$ 19	$ 1,068	$ (14)	**$ 1,073**
Restricted cash	-	-	1	18	-	**19**
Receivables, net	2	-	70	506	-	**578**
Intercompany receivable	102	-	51	95	(248)	**-**
Income taxes receivable	-	-	9	3	-	**12**
Inventory	-	-	48	266	-	**314**
Derivative instruments	109	-	46	112	(17)	**250**
Regulatory assets	-	-	17	77	-	**94**
Prepaid expenses	-	-	4	14	-	**18**
Due from related parties	2	-	-	-	-	**2**
Other current assets	7	-	-	229	-	**236**
Total current assets	222	-	265	2,388	(279)	**2,596**
Property, plant and equipment, net of accumulated depreciation	15	-	2,035	4,419	-	**6,469**
Other assets						
Income taxes receivable	-	-	-	49	-	**49**
Deferred income taxes	-	-	47	19	(34)	**32**
Derivative instruments	35	-	-	167	(34)	**168**
Pension and post-retirement asset	-	-	-	9	-	**9**
Regulatory assets	-	-	100	505	-	**605**
Net investment in direct financing lease	-	-	-	480	-	**480**
Investments in subsidiaries accounted for using the equity method	6,042	-	-	-	(6,042)	**-**
Investments subject to significant influence	509	-	12	624	-	**1,145**
Investment securities	-	-	-	116	-	**116**
Goodwill	-	-	158	106	-	**264**
Due from related parties	-	-	-	3	-	**3**
Intercompany notes receivable	3,051	-	-	2,754	(5,805)	**-**
Other investments - intercompany	-	-	-	98	(98)	**-**
Other long-term assets	16	-	13	74	-	**103**
Total other assets	9,653	-	330	5,004	(12,013)	**2,974**
Total assets	$ 9,890	$ -	$ 2,630	$ 11,811	$ (12,292)	**$ 12,039**

Emera Incorporated
Condensed Consolidated Balance Sheets – (Unaudited) Continued
As at December 31, 2015

As at millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Liabilities and Equity						
Current liabilities						
Short-term debt	$ 14	$ -	$ -	$ 16	$ (14)	**$ 16**
Current portion of long-term debt	250	-	6	18	-	**274**
Accounts payable	17	-	76	301	-	**394**
Income taxes payable	-	-	-	8	-	**8**
Intercompany payable	52	-	92	77	(221)	**-**
Derivative instruments	17	-	36	313	(17)	**349**
Regulatory liabilities	-	-	10	102	-	**112**
Pension and post-retirement liabilities	-	-	-	7	-	**7**
Due to related party	-	-	-	2	-	**2**
Other current liabilities	51	-	24	130	-	**205**
Total current liabilities	401	-	244	974	(252)	**1,367**
Long-term liabilities						
Long-term debt	464	-	389	2,882	-	**3,735**
Intercompany long-term debt	2,631	-	120	3,072	(5,823)	**-**
Deferred income taxes	3	-	343	450	(34)	**762**
Convertible debentures represented by instalment receipts	2,139	-	-	(1,458)	-	**681**
Derivative instruments	34	-	-	96	(34)	**96**
Regulatory liabilities	-	-	12	341	-	**353**
Asset retirement obligations	-	-	-	109	-	**109**
Pension and post-retirement liabilities	13	-	93	197	-	**303**
Other long-term liabilities	5	-	61	233	-	**299**
Total long-term liabilities	5,289	-	1,018	5,922	(5,891)	**6,338**
Equity						
Common stock	2,157	-	312	3,829	(4,141)	**2,157**
Cumulative preferred stock	709	-	425	271	(696)	**709**
Contributed surplus	29	-	45	133	(178)	**29**
Accumulated other comprehensive income (loss)	137	-	245	(169)	(76)	**137**
Retained earnings	1,168	-	341	751	(1,092)	**1,168**
Total Emera Incorporated equity	4,200	-	1,368	4,815	(6,183)	**4,200**
Non-controlling interest in subsidiaries	-	-	-	100	34	**134**
Total equity	4,200	-	1,368	4,915	(6,149)	**4,334**
Total liabilities and equity	$ 9,890	$ -	$ 2,630	$ 11,811	$ (12,292)	**$ 12,039**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)
For the nine months ended September 30, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Net cash provided by (used in) by operating activities	$ 106	$ -	$ 372	$ 611	$ (222)	**$ 867**
Investing activities						
Acquisitions, net of cash acquired	-	-	(8,409)	-	-	**(8,409)**
Additions to property, plant and equipment	(2)	-	(305)	(286)	-	**(593)**
Net purchase of investments subject to significant influence, inclusive of acquisition costs	-	-	-	(171)	-	**(171)**
Net proceeds on sale of investment subject to significant influence	525	-	-	-	-	**525**
Other intercompany investing activities	(2,293)	(4,416)	-	(2,173)	8,882	**-**
Other investing activities	(2)	-	(19)	24	38	**41**
Net cash provided by (used in) investing activities	(1,772)	(4,416)	(8,733)	(2,606)	8,920	**(8,607)**
Financing activities						
Change in short-term debt, net	(10)	-	(6)	(18)	10	**(24)**
Proceeds from long-term debt, net of issuance costs	2,034	4,194	4,451	3	(4,454)	**6,228**
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs	(43)	-	-	1,457	-	**1,414**
Retirement of long-term debt	-	-	(6)	(31)	19	**(18)**
Net borrowings (repayments) under committed credit facilities	(155)	-	13	(91)	-	**(233)**
Issuance of common stock, net of issuance costs	20	242	3,865	164	(4,271)	**20**
Issuance of preferred stock, net of issuance costs	-	-	195	-	(195)	**-**
Dividends on common stock	(155)	-	-	(192)	192	**(155)**
Dividends on preferred stock	(21)	-	(15)	(11)	26	**(21)**
Dividends paid by subsidiaries to non-controlling interest	-	-	-	(1)	(4)	**(5)**
Other financing activities	-	-	(23)	(15)	(11)	**(49)**
Net cash provided by (used in) financing activities	1,670	4,436	8,474	1,265	(8,688)	**7,157**
Effect of exchange rate changes on cash and cash equivalents	(4)	(8)	(2)	(61)	-	**(75)**
Net increase (decrease) in cash and cash equivalents	-	12	111	(791)	10	**(658)**
Cash and cash equivalents, beginning of period	-	-	19	1,068	(14)	**1,073**
Cash and cash equivalents, end of period	$ -	$ 12	$ 130	$ 277	$ (4)	**$ 415**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)
For the nine months ended September 30, 2015

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Net cash provided by (used in) operating activities	$ 120	$ -	$ 150	$ 362	$ (70)	**$ 562**
Investing activities						
Additions to property, plant and equipment	(4)	-	(82)	(207)	-	**(293)**
Net purchase of investments subject to significant influence, inclusive of acquisition costs	(2)	-	-	(66)	-	**(68)**
Proceeds on sale of investment subject to significant influence	-	-	282	-	-	**282**
Other intercompany investing activities	(2,012)	-	-	-	2,012	**-**
Other investing activities	246	-	(19)	310	(559)	**(22)**
Net cash provided by (used in) investing activities	(1,772)	-	181	37	1,453	**(101)**
Financing activities						
Change in short-term debt, net	9	-	-	(278)	(9)	**(278)**
Proceeds from long-term debt, net of issuance costs	-	-	31	470	(76)	**425**
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs	1,860	-	-	(1,267)	-	**593**
Retirement of long-term debt	-	-	(361)	(274)	620	**(15)**
Net borrowings (repayments) under committed credit facilities	(85)	-	(6)	(399)	-	**(490)**
Issuance of common stock, net of issuance costs	7	-	-	2,012	(2,012)	**7**
Issuance of preferred stock, net of issuance costs	-	-	-	6	(6)	**-**
Dividends on common stock	(116)	-	-	(70)	70	**(116)**
Dividends on preferred stock	(23)	-	(11)	(19)	30	**(23)**
Dividends paid by subsidiaries to non-controlling interest	-	-	-	(2)	(9)	**(11)**
Other financing activities	-	-	(12)	(4)	-	**(16)**
Net cash provided by (used in) financing activities	1,652	-	(359)	175	(1,392)	**76**
Effect of exchange rate changes on cash and cash equivalents	-	-	12	25	-	**37**
Net increase (decrease) in cash and cash equivalents	-	-	(16)	599	(9)	**574**
Cash and cash equivalents, beginning of period	-	-	38	193	(10)	**221**
Cash and cash equivalents, end of period	$ -	$ -	$ 22	$ 792	$ (19)	**$ 795**