

EMERA INCORPORATED

**Unaudited Condensed Consolidated
Interim Financial Statements
September 30, 2015 and 2014**

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	
	2015	2014	2015	2014
Operating revenues				
Regulated	\$ 515.6	\$ 488.3	\$ 1,659.1	\$ 1,586.4
Non-regulated	138.4	74.1	432.2	592.9
Total operating revenues	654.0	562.4	2,091.3	2,179.3
Operating expenses				
Regulated fuel for generation and purchased power	185.9	188.8	614.6	631.4
Regulated fuel adjustment mechanism and fixed cost deferrals (note 5)	15.8	15.6	31.3	40.9
Non-regulated fuel for generation and purchased power	57.9	50.8	249.2	326.2
Non-regulated direct costs	14.7	16.1	39.7	37.3
Operating, maintenance and general	189.5	139.4	502.1	425.5
Provincial, state and municipal taxes	14.8	13.2	43.7	39.1
Depreciation and amortization	84.9	78.5	252.0	247.0
Total operating expenses	563.5	502.4	1,732.6	1,747.4
Income from operations	90.5	60.0	358.7	431.9
Income from equity investments (note 6)	24.1	28.9	82.2	51.2
Other income (expenses), net (note 7)	3.7	3.2	26.3	9.4
Interest expense, net (note 8)	49.3	44.5	141.7	135.1
Income before provision for income taxes	69.0	47.6	325.5	357.4
Income tax expense (recovery) (note 9)	11.7	(1.7)	71.7	59.9
Net income	57.3	49.3	253.8	297.5
Non-controlling interest in subsidiaries	7.5	6.1	18.4	15.8
Net income of Emera Incorporated	49.8	43.2	235.4	281.7
Preferred stock dividends	14.8	15.0	30.3	26.2
Net income attributable to common shareholders	\$ 35.0	\$ 28.2	\$ 205.1	\$ 255.5
Weighted average shares of common stock outstanding (in millions) (note 10)				
Basic	146.0	143.6	145.4	142.9
Diluted	147.1	144.3	146.5	147.5
Earnings per common share (note 10)				
Basic	\$ 0.24	\$ 0.20	\$ 1.41	\$ 1.79
Diluted	\$ 0.24	\$ 0.20	\$ 1.40	\$ 1.77
Dividends per common share declared	\$ 0.8750	\$ 0.7500	\$ 1.6625	\$ 1.4750

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	
	2015	2014	2015	2014
Net income	\$ 57.3	\$ 49.3	\$ 253.8	\$ 297.5
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	160.0	83.5	331.7	91.7
Cash flow hedges				
Net derivative gains (losses) (2)	(12.7)	(15.8)	(26.4)	(7.9)
Less: reclassification adjustment for losses (gains) included in income (3)	3.4	1.9	4.3	1.5
Net effects of cash flow hedges	(9.3)	(13.9)	(22.1)	(6.4)
Unrealized gains (losses) on available-for-sale investment				
Unrealized gain (loss) arising during the period	(3.8)	(0.8)	(4.3)	0.3
Net unrealized holding gains (losses)	(3.8)	(0.8)	(4.3)	0.3
Net change in unrecognized pension and post-retirement benefit obligation (4)	10.5	8.3	46.2	27.2
Other comprehensive income (loss) (5)	157.4	77.1	351.5	112.8
Comprehensive income (loss)	214.7	126.4	605.3	410.3
Comprehensive income (loss) attributable to non-controlling interest	18.6	12.4	40.0	22.7
Comprehensive income (loss) of Emera Incorporated	\$ 196.1	\$ 114.0	\$ 565.3	\$ 387.6

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

1) Net of tax recovery of \$0.4 million (2014 - \$0.5 million tax recovery) for the three months ended September 30, 2015 and tax expense of \$3.4 million (2014 - \$0.9 million tax expense) for the nine months ended September 30, 2015.

2) Net of tax expense of \$0.1 million (2014 - \$0.5 million tax recovery) for the three months ended September 30, 2015 and tax expense of \$0.7 million (2014 - \$4.2 million tax expense) for the nine months ended September 30, 2015.

3) Net of tax expense of \$0.5 million (2014 - \$0.8 million tax expense) for the three months ended September 30, 2015 and tax recovery of \$1.4 million (2014 - \$0.6 million tax recovery) for the nine months ended September 30, 2015.

4) Net of tax expense/recovery of nil (2014 - \$0.1 million tax expense) for the three months ended September 30, 2015 and tax expense of \$9.1 million (2014 - \$0.7 million tax expense) for the nine months ended September 30, 2015.

5) Net of tax expense of \$0.2 million (2014 - \$0.1 million tax recovery) for the three months ended September 30, 2015 and tax expense of \$11.8 million (2014 - \$5.2 million tax expense) for the nine months ended September 30, 2015.

Emera Incorporated

Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars	September 30 2015	December 31 2014
Assets		
Current assets		
Cash and cash equivalents	\$ 795.0	\$ 221.1
Restricted cash (note 12)	19.6	15.9
Receivables, net (note 13)	456.2	514.2
Income taxes receivable	6.3	4.8
Inventory (note 14)	286.5	294.5
Deferred income taxes	50.0	27.9
Derivative instruments (notes 15 and 16)	173.2	136.5
Regulatory assets (notes 5 and 17)	74.6	115.0
Prepaid expenses	36.4	24.7
Due from related parties (note 18)	1.4	3.5
Other current assets (note 19)	32.9	80.6
Total current assets	1,932.1	1,438.7
Property, plant and equipment , net of accumulated depreciation of \$3,656.2 and \$3,362.0, respectively	6,080.3	5,610.2
Other assets		
Income taxes receivable	48.3	28.9
Deferred income taxes	39.8	33.7
Derivative instruments (notes 15 and 16)	141.4	92.0
Pension and post-retirement asset (note 20)	5.9	5.9
Regulatory assets (notes 5 and 17)	560.7	495.7
Net investment in direct financing lease	481.0	484.5
Investments subject to significant influence (note 6)	898.2	1,006.8
Available-for-sale investments (note 21)	110.4	84.4
Goodwill	255.6	221.5
Intangibles, net of accumulated amortization of \$94.3 and \$88.3, respectively	161.7	134.3
Due from related parties (note 18)	2.5	2.5
Other long-term assets (note 22)	255.1	205.3
Total other assets	2,960.6	2,795.5
Total assets	\$ 10,973.0	\$ 9,844.4

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

Emera Incorporated Consolidated Condensed Balance Sheets – Continued

As at millions of Canadian dollars	September 30 2015	December 31 2014
Liabilities and Equity		
Current liabilities		
Short-term debt (note 24)	\$ -	\$ 257.6
Current portion of long-term debt	93.7	94.5
Accounts payable	364.6	370.7
Income taxes payable	9.3	33.8
Convertible debentures represented by instalment receipts (note 26)	632.7	-
Deferred income taxes	0.1	15.7
Derivative instruments (notes 15 and 16)	128.0	127.4
Regulatory liabilities (note 17)	114.9	51.0
Pension and post-retirement liabilities (note 20)	7.4	7.5
Due to related party (note 18)	1.7	1.6
Other current liabilities (note 23)	251.4	186.8
Total current liabilities	1,603.8	1,146.6
Long-term liabilities		
Long-term debt (note 25)	3,677.6	3,660.3
Deferred income taxes	739.9	601.4
Derivative instruments (notes 15 and 16)	98.3	77.4
Regulatory liabilities (note 17)	229.4	158.9
Asset retirement obligations	109.7	106.2
Pension and post-retirement liabilities (note 20)	348.5	360.7
Other long-term liabilities	74.1	27.5
Total long-term liabilities	5,277.5	4,992.4
Commitments and contingencies (note 27)		
Equity		
Common stock, no par value, unlimited shares authorized, 145.33 million and 143.78 million shares issued and outstanding, respectively (note 28)	2,078.5	2,016.4
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 (note 29)	709.5	709.5
Contributed surplus	9.8	8.8
Accumulated other comprehensive loss (note 11)	(17.7)	(347.6)
Retained earnings	976.7	1,011.7
Total Emera Incorporated equity	3,756.8	3,398.8
Non-controlling interest in subsidiaries (note 30)	334.9	306.6
Total equity	4,091.7	3,705.4
Total liabilities and equity	\$ 10,973.0	\$ 9,844.4

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

Approved on behalf of the Board of Directors

“M. Jacqueline Sheppard”

Chair of the Board

“Christopher G. Huskison”

President and Chief Executive Officer

Emera Incorporated

Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Nine months ended September	
	2015	2014
Operating activities		
Net income	\$ 253.8	\$ 297.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	260.6	256.8
Income from equity investments, net of dividends	(24.0)	3.9
Allowance for equity funds used during construction	(3.2)	(7.5)
Deferred income taxes, net	7.5	-
Net change in pension and post-retirement liabilities	28.4	0.7
Regulated fuel adjustment mechanism and fixed cost deferrals	28.6	35.1
Net change in fair value of derivative instruments	(0.9)	(26.6)
Net change in regulatory assets and liabilities	(5.0)	0.3
Other operating activities, net	58.0	4.1
Changes in non-cash working capital:		
Receivables, net	94.8	137.4
Income taxes receivable	(17.5)	(0.3)
Inventory	22.2	(19.9)
Prepaid expenses	(9.9)	(26.8)
Due from related party	2.1	-
Other current assets	(1.4)	(0.6)
Accounts payable	(61.9)	(65.4)
Income taxes payable	(28.3)	(4.6)
Other current liabilities	(20.1)	1.2
Net cash provided by operating activities	583.8	585.3
Investing activities		
Additions to property, plant and equipment	(283.0)	(253.0)
(Increase) decrease in restricted cash	(1.5)	4.9
Net purchase of investments subject to significant influence, inclusive of acquisition costs	(68.3)	(145.2)
Allowance for borrowed funds used during construction	(3.9)	(3.3)
Retirement spending, net of salvage	(5.0)	(4.7)
Loan to related party	-	(5.8)
Proceeds on sale of investment subject to significant influence	282.3	-
Additions to intangible assets	(27.0)	(2.3)
Other investing activities	(15.8)	6.0
Net cash used in investing activities	(122.2)	(403.4)

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

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited) – Continued

For the millions of Canadian dollars	Nine months ended September	
	2015	2014
Financing activities		
Change in short-term debt, net	(277.7)	(132.7)
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs (note 26)	592.5	-
Retirement of long-term debt	(138.6)	(23.9)
Proceeds from long-term debt	425.0	152.0
Net borrowings (repayments) under committed credit facilities	(365.7)	(298.8)
Issuance of common stock, net of issuance costs	62.0	284.9
Issuance of preferred stock, net of issuance costs	-	192.0
Dividends on common stock	(171.4)	(154.6)
Dividends on preferred stock	(23.2)	(18.4)
Dividends paid by subsidiaries to non-controlling interest	(10.9)	(8.8)
Other financing activities	(16.3)	2.5
Net cash provided by (used in) financing activities	75.7	(5.8)
Effect of exchange rate changes on cash and cash equivalents	36.6	4.1
Net increase in cash and cash equivalents	573.9	180.2
Cash and cash equivalents, beginning of period	221.1	100.8
Cash and cash equivalents, end of period	\$ 795.0	\$ 281.0
Cash and cash equivalents consists of:		
Cash	\$ 720.6	\$ 104.6
Short-term investments	74.4	176.4
Cash and cash equivalents	\$ 795.0	\$ 281.0

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 Loss ("AOCL")	Retained Earnings	Emera Total Equity	Non- Controlling Interest	Total Equity
For the nine months ended September 30, 2015								
Balance, December 31, 2014	\$ 2,016.4	\$ 709.5	\$ 8.8	\$ (347.6)	\$ 1,011.7	\$ 3,398.8	\$ 306.6	\$ 3,705.4
Net income of Emera Incorporated	-	-	-	-	235.4	235.4	18.4	253.8
Other comprehensive income (loss), net of tax expense of \$11.8 million	-	-	-	329.9	-	329.9	21.6	351.5
Dividends declared on preferred stock (Series A: \$0.98470/share, Series B: \$0.15080/share, Series C: \$1.0250/share, Series E: \$1.1250/share, and Series F: \$1.06250/share)	-	-	-	-	(30.3)	(30.3)	-	(30.3)
Dividends declared on common stock (\$1.6625/share)	-	-	-	-	(240.1)	(240.1)	-	(240.1)
Dividends paid and payable by subsidiaries to non-controlling interest	-	-	-	-	-	-	(2.1)	(2.1)
Common stock issued under purchase plan	60.0	-	-	-	-	60.0	-	60.0
Senior management stock options exercised	1.5	-	(0.1)	-	-	1.4	-	1.4
Stock option expense	-	-	1.1	-	-	1.1	-	1.1
Other stock-based compensation	0.6	-	-	-	-	0.6	-	0.6
Preferred dividends paid and payable by subsidiaries to non-controlling interest	-	-	-	-	-	-	(9.2)	(9.2)
Other	-	-	-	-	-	-	(0.4)	(0.4)
Balance, September 30, 2015	\$ 2,078.5	\$ 709.5	\$ 9.8	\$ (17.7)	\$ 976.7	\$ 3,756.8	\$ 334.9	\$ 4,091.7

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 Loss ("AOCL")	Retained Earnings	Emera Total Equity	Non- Controlling Interest	Total Equity
For the nine months ended September 30, 2014								
Balance, December 31, 2013	\$ 1,703.0	\$ 514.0	\$ 4.1	\$ (430.1)	\$ 817.2	\$ 2,608.2	\$ 289.0	\$ 2,897.2
Net income of Emera Incorporated	-	-	-	-	281.7	281.7	15.8	297.5
Other comprehensive income (loss), net of tax expense of \$5.2 million	-	-	-	105.9	-	105.9	6.9	112.8
Issuance of common stock, net of after-tax issuance costs	243.0	-	-	-	-	243.0	-	243.0
Dividends declared on preferred stock (Series A: \$1.1000/share, Series C: \$1.1025/share, Series E: \$1.1250/share and Series F: \$0.4606/share)	-	-	-	-	(26.2)	(26.2)	-	(26.2)
Dividends declared on common stock (\$1.4750/share)	-	-	-	-	(210.0)	(210.0)	-	(210.0)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(1.3)	(1.3)
Issuance of preferred shares, net of after-tax issuance costs	-	195.8	-	-	-	195.8	-	195.8
Common stock issued under purchase plan	47.0	-	-	-	-	47.0	-	47.0
Senior management stock options exercised	0.6	-	-	-	-	0.6	-	0.6
Stock option expense	-	-	0.9	-	-	0.9	-	0.9
Other stock-based compensation	0.6	-	-	-	-	0.6	-	0.6
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(8.7)	(8.7)
Other	-	-	4.6	4.8	(2.9)	6.5	(1.1)	5.4
Balance, September 30, 2014	\$ 1,994.2	\$ 709.8	\$ 9.6	\$ (319.4)	\$ 859.8	\$ 3,254.0	\$ 300.6	\$ 3,554.6

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, 2015 and 2014

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, 2015 included the following:

- Nova Scotia Power Inc. (“NSPI”), which is a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving 505,000 customers;
- Emera Maine provides electric transmission and distribution services to 158,000 customers in the State of Maine in the United States;
- an 80.7 per cent interest in Emera (Caribbean) Incorporated (“ECI”), the parent of 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 41.8 per cent indirect interest, through ECI’s 51.9 per cent controlling interest, in Dominica Electricity Services Ltd. (“Domlec”), an integrated utility on the island of Dominica, serving 35,000 customers; and a 15.4 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”);
- 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 in service in 2017. ENL’s two investments are:
 - 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, between the island of Newfoundland and Nova Scotia;
 - 49.6 per cent interest in the partnership capital of Labrador-Island Link Limited Partnership, (“LIL”), which is a \$3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of the Muskrat Falls energy between Labrador and the island of Newfoundland;
- 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 Maritime Canada and the northeastern United States;

Emera Incorporated and its subsidiaries also own investments in other energy-related 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”), 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;
 - a 49.0 per cent interest in Northeast Wind Partners II, LLC (“NWP”), a 419 MW portfolio of wind energy projects in the northeastern United States, which was sold on January 29, 2015;
- 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 Utility Services Inc., which is a utility services contractor primarily operating in Atlantic Canada;
- Emera Utility Services (Bahamas) Limited (“EUS Bahamas”) provides utility construction services and plant operation services in The Bahamas;
- a 20.8 per cent investment in Algonquin Power & Utilities Corp. (“APUC”), which is a public company traded on the Toronto Stock Exchange under the symbol “AQN”;
- a 3.3 per cent investment in OpenHydro Group Ltd. (“Open Hydro”);
- and other investments.

Pending acquisition

On September 4, 2015, Emera entered into an Agreement and Plan of Merger pursuant to which, Emera US Inc., a wholly owned indirect subsidiary of Emera, will merge with and into TECO Energy, Inc. (“TECO Energy”), and TECO Energy will survive the merger and become a wholly owned indirect subsidiary of Emera. TECO Energy shareholders will receive \$27.55 USD per common share in cash, which represents an aggregate purchase price of approximately \$10.4 billion USD when including consolidation of approximately \$3.9 billion USD of debt.

The closing of the acquisition, which is expected to occur by mid-2016, is subject to TECO Energy common shareholder approval and certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Federal Energy Regulatory Commission, the Committee on Foreign Investment in the United States, compliance with any applicable requirement under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the satisfaction of closing conditions.

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 which serves more than 700,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves more than 350,000 customers across Florida; and New Mexico Gas Co., also a regulated gas distribution utility which serves more than 510,000 customers across New Mexico.

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”). These unaudited condensed consolidated interim financial statements do not contain all disclosures required by USGAAP for annual audited financial statements. Accordingly, the financial statements should be read in conjunction with Emera Incorporated’s annual audited financial statements as at and for the year ended December 31, 2014.

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, 2015.

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 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, 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 a substantial portion of Emera’s electricity business is located. Certain quarters may also be impacted by the number and severity of storms.

2. CHANGE IN ACCOUNTING POLICY

Business Combinations – Simplifying the Accounting for Measurement-Period Adjustments, Accounting Standard Update (“ASU”) Number (“No.”) 2015-16

In September 2015, the Financial Accounting Standards Board (“FASB”) issued ASU 2015-16, Business Combinations – *Simplifying the Accounting for Measurement-Period Adjustments*. The amendment applies to entities that have reported provisional amounts related to a business combination for which the accounting is incomplete by the end of the reporting period and have an adjustment to provisional amounts previously recognized during a later measurement period. Changes in provisional amounts recorded for acquired assets and liabilities are to be adjusted in the period the adjustment is known, with a corresponding adjustment booked to goodwill. The acquirer is no longer required to revise comparative information from prior years for the effect of changes in provisional amounts. The Company has adopted ASU 2015-16 effective September 25, 2015, with no impact on the consolidated financial statements as a result of implementation of this standard.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers, ASU No. 2014-09

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification (“ASC”), Topic 606. ASC 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. On July 9, 2015, the FASB deferred the effective date by one year. This standard will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Income Statement – Extraordinary and Unusual Items, ASU No. 2015-01

In January 2015, the FASB issued ASU 2015-01, *Income Statement – Extraordinary and Unusual Items*, which simplifies the income statement presentation requirements by eliminating the concept of extraordinary items. ASU No. 2015-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Consolidation, ASU No. 2015-02

In February 2015, the FASB issued ASU 2015-02, *Consolidation*, which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. All legal entities are subject to re-evaluation under the revised consolidation model. ASU No. 2015-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Interest – Imputation of Interest, No. ASU 2015-03

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 in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected by the amendments in the update. ASU No. 2015-03 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. The adoption of this update will result in the reclassification of debt issuance costs from “Other long-term assets” to “Long-term debt” and “Convertible debentures represented by instalment receipts” on the Company’s consolidated balance sheets. As at September 30, 2015, debt issuance costs included in “Other long-term assets” were \$61.2 million (December 31, 2014 - \$18.8 million).

In August 2015, the FASB issued ASU 2015-15, *Interest – Imputation of Interest – Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, which clarifies that the guidance in ASU No. 2015-03 does not apply to line-of-credit arrangements. ASU No. 2015-15 permits an entity to defer and present debt issuance costs as an asset and subsequently amortize these costs ratably over the time of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. As at September 30, 2015, debt issuance costs associated with line-of-credit arrangements included in “Other long-term assets” were \$3.6 million (December 31, 2014 - \$4.1 million) on the Company’s consolidated balance sheets.

Compensation – Retirement Benefits, ASU No. 2015-04

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. ASU No. 2015-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company does not expect the adoption of this standard to have an impact on its consolidated financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU No. 2015-05

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, then the customer should 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 should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. ASU No. 2015-05 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Fair Value Measurement Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), ASU No. 2015-07

In May 2015, the FASB issued ASU 2015-07 removing the requirement to categorize and disclose, within the fair value hierarchy, all investments for which fair value is measured using the net asset value per share as a practical expedient. ASU No. 2015-07 is effective beginning after December 15, 2015 and requires retrospective application. The adoption of this update will result in disclosure of all investments for which fair value is measured using the net asset value per share methodology, outside of the fair-value hierarchy. As at September 30, 2015, total investments measured using the net asset value per share were \$50.3 million (December 31, 2014 - \$31.7 million).

Technical Corrections and Improvements, ASU No. 2015-10

In June 2015, the FASB issued ASU 2015-10, *Technical Corrections and Improvements*, covering a wide range of topics in the codification to correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost. ASU No. 2015-10 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Inventory – Simplifying the Measurement of Inventory, ASU No. 2015-11

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. ASU No. 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

4. SEGMENT INFORMATION

Emera manages its reportable segments separately due 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, 2015, Emera has six reportable segments, specifically:

- NSPI;
- Emera Maine;
- Emera Caribbean (ECI and its subsidiaries including BLPC and Domlec; GBPC and EUS Bahamas and an equity investment in Lucelec);
- Pipelines (Brunswick Pipeline and an equity investment in M&NP);
- Emera Energy (Emera Energy Services, New England Gas Generating Facilities, Bayside Power, Brooklyn Energy, equity investments in Bear Swamp and NWP for January 1, 2015 to January 29, 2015, when Emera sold its interest in NWP); and
- Corporate and Other (Emera Utility Services, ENL, Corporate, other strategic investments (including APUC), holding companies, and inter-segment eliminations).

millions of Canadian dollars	NSPI	Emera Maine	Emera Caribbean	Pipelines	Emera Energy	Corporate Other and Eliminations	Total
For the three months ended September 30, 2015							
Operating revenues from external customers (1)	\$ 304.9	\$ 78.3	\$ 120.2	\$ 13.0	\$ 114.4	\$ 5.0	\$ 635.8
Inter-segment revenues (1)	-	-	2.7	-	8.8	6.7	18.2
Total operating revenues	304.9	78.3	122.9	13.0	123.2	11.7	654.0
Net income (loss) attributable to common shareholders	4.9	14.7	13.6	9.4	27.5	(35.1)	35.0
For the nine months ended September 30, 2015							
Operating revenues from external customers (1)	1,078.8	213.7	330.0	39.1	370.7	12.7	2,045.0
Inter-segment revenues (1)	-	-	7.5	-	23.1	15.7	46.3
Total operating revenues	1,078.8	213.7	337.5	39.1	393.8	28.4	2,091.3
Net income attributable to common shareholders	89.8	39.9	27.2	27.2	59.2	(38.2)	205.1
For the three months ended September 30, 2014							
Operating revenues from external customers (1)	\$ 289.0	\$ 61.9	\$ 124.5	\$ 12.6	\$ 51.1	\$ 9.7	\$ 548.8
Inter-segment revenues (1)	-	-	2.8	-	5.2	5.6	13.6
Total operating revenues	289.0	61.9	127.3	12.6	56.3	15.3	562.4
Net income (loss) attributable to common shareholders	10.9	13.3	8.2	8.7	(11.0)	(1.9)	28.2
For the nine months ended September 30, 2014							
Operating revenues from external customers (1)	1,015.4	179.0	356.9	36.4	545.2	19.8	2,152.7
Inter-segment revenues (1)	0.1	-	6.9	-	8.3	11.3	26.6
Total operating revenues	1,015.5	179.0	363.8	36.4	553.5	31.1	2,179.3
Net income attributable to common shareholders	94.8	30.7	22.6	24.2	91.7	(8.5)	255.5

(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. Eliminated transactions are included in determining reportable segments.

5. REGULATED FUEL ADJUSTMENT MECHANISM AND FIXED COST DEFERRALS

Regulated fuel adjustment mechanism and fixed cost deferrals over (under) recovery consists of the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Regulated fuel adjustment mechanism (see chart below)	\$ 12.1	\$ 6.9	\$ 27.5	\$ 4.9
Application of non-fuel revenue per December 2, 2014 Nova Scotia Utility and Review Board ("UARB") settlement agreement as discussed below	12.5	-	30.1	-
Regulated fixed cost deferral related to 2013/2014 rate stabilization	-	8.7	-	36.0
Regulated fixed cost deferral related to 2015 demand side management	(8.8)	-	(26.3)	-
	\$ 15.8	\$ 15.6	\$ 31.3	\$ 40.9

Regulated Fuel Adjustment Mechanism

The regulated fuel adjustment mechanism ("FAM") included in the 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 is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities" on the Consolidated Balance Sheets; and
- The recovery from (rebate to) customers of under (over) recovered fuel costs from prior years.

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Over (under) recovery of current year Fuel Costs	\$ 0.6	\$ 6.6	\$ (15.1)	\$ 4.6
Recovery from customers of prior years' Fuel Costs	11.5	-	42.6	-
FAM audit disallowance	-	0.3	-	0.3
Regulated fuel adjustment mechanism	\$ 12.1	\$ 6.9	\$ 27.5	\$ 4.9

The deferred FAM amounts are recognized as a "Regulatory asset" or "Regulatory liability" on the Balance Sheets. The FAM regulatory liability balance of \$8.3 million is disclosed in Note 17 and includes associated interest that is recorded as "Interest expense, net" on the Consolidated Statements of Income.

A settlement agreement, approved by the UARB in November 2014, is estimated to result in approximately \$56.0 million of the outstanding FAM balance being collected in 2015. The settlement agreement also reduced the FAM regulatory asset at the end of 2014 of \$86.1 million by \$38.2 million via an offset from the liability balance in the Rate Stabilization deferral account, such that at December 31, 2014 the FAM regulatory asset was \$47.9 million.

Through a related settlement agreement with stakeholders in December 2014, NSPI agreed to apply any non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This is effective as of January 1, 2015 until the next General Rate Application ("GRA") approval or similar process where non-fuel rates are adjusted. This settlement agreement requires NSPI to contribute a minimum of \$41.3 million to the FAM deferral account by the end of 2015. As at September

30, 2015, NSPI had exceeded the minimum contribution commitment through the \$38.2 million referred to above and an additional \$30.1 million year-to-date in 2015.

The deferred DSM amount is recognized as a "Regulatory asset" on the Consolidated Balance Sheets.

Regulated Fixed Cost Deferrals

NSPI has the following regulatory assets arising from UARB approved fixed cost deferral mechanisms:

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a fixed cost recovery for fiscal 2013 and 2014 as part of a rate stabilization plan. As directed by the UARB on November 25, 2014, as discussed above under the Regulated Fuel Adjustment Mechanism, the rate stabilization deferral liability balance of \$38.2 million as at December 31, 2014, was applied against the FAM balance in 2014.

2015 DSM Deferral

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 are set for 2015 at \$35.0 million and are being deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of \$102.0 million for the three-year period of 2016 through 2018. A decision on the timing of cost recovery will be made in the future.

The Program Costs are recorded in Operating, maintenance and general ("OM&G"), with an offsetting credit in "Regulated fuel adjustment mechanism and fixed cost deferrals" on Emera's Consolidated Income Statements, with no effect on net earnings, with the exception of interest on the balance.

The deferred DSM amounts are recognized as a "Regulatory asset" or "Regulatory liability" on the Balance Sheets. The DSM regulatory asset balance of \$27.1 million is disclosed in Note 17 and includes associated interest that is recorded as "Interest expense, net" on the Consolidated Statements of Income.

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value as at		Equity Income for the		Equity Income for the		Percentage of
	September 30	December 31	three months ended September 30	September 30	nine months ended September 30	September 30	Ownership
millions of Canadian dollars	2015	2014	2015	2014	2015	2014	2015
APUC (1) (2)	\$ 360.4	\$ 336.4	\$ 3.8	\$ 13.6	\$ 18.9	24.8	20.8
M&NP (3)	186.2	171.8	5.8	4.9	16.5	13.1	12.9
NSPML (4)	170.3	159.3	3.8	3.2	11.1	5.1	100.0
LIL (5)	152.8	80.1	2.4	1.7	5.8	4.8	49.6
Lucelec (3)	38.2	31.7	0.8	0.5	2.2	1.8	15.4
Cape Sharp Tidal Venture Ltd.	5.1	3.6	-	-	-	-	20.0
Chester Static Var Compensator	5.1	4.4	-	-	-	-	50.0
Maine Electric Power Company Inc.	3.8	2.9	0.2	0.1	0.4	0.5	21.7
Maine Yankee Atomic Power Company (3)	0.4	0.3	-	-	-	-	12.0
Bear Swamp (6)	(24.1)	(20.8)	7.3	12.3	23.0	23.7	50.0
NWP (7)	-	237.1	-	(7.4)	4.3	(22.6)	49.0
	\$ 898.2	\$ 1,006.8	\$ 24.1	\$ 28.9	\$ 82.2	51.2	

(1) As at September 30, 2015, the market price / share is \$9.44 (December 31, 2014 – \$9.64), which indicates a fair market value of this investment of \$473.2 million (December 31, 2014 – \$483.2 million). Emera holds 50.1 million shares as at September 30, 2015 at an average book value of \$7.19 per share. Carrying value reflects a cash cost of \$260.7 million, plus non-cash gains recognized on conversion of subscriptions receipts into common shares, dilution gains or losses, and equity income or loss, less dividends received. As at September 30, 2015, Emera held 12.024 million outstanding subscription receipts at an average conversion price of \$9.19, which are recorded in "Other long-term assets" on the Consolidated Balance Sheets.

(2) Emera's Strategic Investment Agreement with APUC and a ruling by the Maine Public Utilities Commission ("MPUC") limits Emera's equity ownership in APUC to 25 per cent of APUC's voting securities. The MPUC also stipulated Emera's dollar investment in APUC cannot exceed 5 per cent of Emera's total assets. As at September 30, 2015, Emera is in compliance with both of these requirements.

(3) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method. This is consistent with industry practice for similar investments with significant influence.

(4) Until Emera achieved certain critical milestones, including its financing and approvals to enable it to proceed to full construction, Emera recorded the Maritime Link Project development and engineering costs in "Property, plant and equipment" on its Consolidated Balance Sheets. In Q2 2014, when the critical milestones were achieved, and Nalcor Energy was deemed the beneficiary of the asset for financial reporting purposes, Emera began recording the Maritime Link Project as an equity investment, with equity earnings equal to the return on equity component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017. At that time, Emera will record equity earnings equal to 100 per cent of NSPML net earnings.

(5) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued. Emera's share of the total partnership capital is 49.6 per cent.

(6) The Bear Swamp investment has a negative balance as a result of Emera receiving dividends in excess of the investment cost.

(7) On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for proceeds of \$282.3 million (\$223.3 million USD).

Equity investments include a \$104.1 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 and intangible assets. Intangible assets with definite lives are subject to amortization based on the estimated remaining useful lives of the assets.

Emera equity accounts for its variable interest investment in NSPML as an equity investment (see Note 31). NSPML's consolidated summarized statement of income and balance sheet are illustrated as follows:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014*
Statement of Income				
Other income (expenses), net	\$ 3.8	\$ 3.2	\$ 11.1	\$ 5.1
Net income (loss)	\$ 3.8	\$ 3.2	\$ 11.1	\$ 5.1

*Emera began recording NSPML as an equity investment in Q2 2014.

As at millions of Canadian dollars	September 30	December 31
	2015	2014
Balance Sheet		
Current assets	\$ 410.8	\$ 388.4
Non-current assets	1,230.3	1,184.8
Total assets	\$ 1,641.1	\$ 1,573.2
Current liabilities	\$ 140.4	\$ 100.4
Non-current liabilities	1,330.3	1,313.5
Equity	170.4	159.3
Total liabilities and equity	\$ 1,641.1	\$ 1,573.2

7. 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	
	2015	2014	2015	2014
Gain on sale of NWP investment	\$ -	\$ -	\$ 18.6	\$ -
Foreign exchange gains (losses)	4.5	0.8	6.0	2.4
Allowance for equity funds used during construction	1.4	2.0	3.2	7.5
Investment income	0.3	0.6	0.9	1.4
Earnings share mechanism in GBPC	(0.1)	1.0	0.3	1.0
Amortization of defeasance costs	(1.6)	(1.7)	(5.0)	(6.2)
Other	(0.8)	0.5	2.3	3.3
	\$ 3.7	\$ 3.2	\$ 26.3	\$ 9.4

8. 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	
	2015	2014	2015	2014
Interest on debt	\$ 48.9	\$ 46.2	\$ 145.0	\$ 140.5
Allowance for borrowed funds used during construction	(0.9)	(1.4)	(3.9)	(3.3)
Interest revenue	(1.3)	(1.9)	(5.2)	(7.3)
Other	2.6	1.6	5.8	5.2
	\$ 49.3	\$ 44.5	\$ 141.7	\$ 135.1

9. INCOME TAXES

The income tax provision differs from that computed using the combined federal and Nova Scotia provincial statutory income tax rate for the following reasons:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Income before provision for income taxes	\$ 69.0	\$ 47.6	\$ 325.5	\$ 357.4
Statutory income tax rate	31.0%	31.0%	31.0%	31.0%
Income taxes, at statutory rate	21.4	14.8	100.9	110.8
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	(3.1)	(4.6)	(14.9)	(27.2)
Tax effect of equity earnings	(2.0)	(3.3)	(7.0)	(6.0)
Other	(4.6)	(8.6)	(7.3)	(17.7)
Income tax expense (recovery)	\$ 11.7	\$ (1.7)	\$ 71.7	\$ 59.9
Effective income tax rate	17.0%	(3.6%)	22.0%	16.8%

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Income tax expense (recovery) – current	\$ 3.9	\$ 24.4	\$ 64.2	\$ 59.9
Income tax expense (recovery) – deferred	7.8	(26.1)	7.5	-
Income tax expense (recovery)	\$ 11.7	\$ (1.7)	\$ 71.7	\$ 59.9

NSPI and the Canada Revenue Agency (“CRA”) are currently in a dispute with respect to the timing of certain tax deductions for its 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 \$62.3 million, including taxes and interest. NSPI has prepaid \$22.7 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 with respect to NSPI’s deductions. 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 taxation year be similarly reassessed, further payments will be required; however, the ultimate permissibility of the 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.

10. 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	
	2015	2014	2015	2014
Numerator				
Net income attributable to common shareholders	\$ 35.0	\$ 28.2	\$ 205.1	\$ 255.5
Preferred stock dividends of subsidiary (1)	-	-	-	5.8
Diluted numerator	35.0	28.2	205.1	261.3
Denominator				
Weighted average shares of common stock outstanding	145.1	142.8	144.5	142.1
Weighted average deferred share units outstanding	0.9	0.8	0.9	0.8
Weighted average shares of common stock outstanding – basic	146.0	143.6	145.4	142.9
Effect of dilutive preferred stock of a subsidiary (1)	-	-	-	3.9
Dividend reinvestment plan	0.5	0.4	0.5	0.4
Stock-based compensation	0.6	0.3	0.6	0.3
Weighted average shares of common stock outstanding – diluted	147.1	144.3	146.5	147.5
Earnings per common share				
Basic	\$ 0.24	\$ 0.20	\$ 1.41	\$ 1.79
Diluted (1)	\$ 0.24	\$ 0.20	\$ 1.40	\$ 1.77

(1) The calculation of diluted earnings per share for the three and nine months ended September 30, 2015 excluded the impact of \$1.9 million (2014 – \$1.9 million) and \$5.8 million (2014 – \$nil) in preferred stock dividends of a subsidiary and 3.0 million (2014 – 3.9 million) and 3.0 million (2014 – Nil) in potential common shares that had an anti-dilutive effect.

Following the satisfaction of all conditions precedent to the closing of the acquisition of TECO Energy, at the option of holders and provided that payment of the final instalment has been made, each Debenture will be convertible into common shares of Emera at any time after the Final Instalment Date, but prior to maturity or redemption by the Company at a conversion price of \$41.85 per common share, being a conversion rate of 23.8949 common shares per \$1,000 principal amount of Debentures (note 25). Accordingly, a total of approximately 45.4 million common shares could be issued to convert the Debentures into common shares. When the conditions for closing the acquisition are met, the Debentures will be included as a component of the Company's diluted EPS.

11. 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 available-for- sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCL
For the nine months ended September 30, 2015					
Balance, January 1, 2015	\$ (7.9)	\$ (424.7)	\$ 2.6	\$ 82.4	\$ (347.6)
Other comprehensive income (loss) before reclassifications	(26.4)	-	(3.7)	309.5	279.4
Amounts reclassified from accumulated other comprehensive income loss (gain)	4.3	46.2	-	-	50.5
Net current period other comprehensive income (loss)	(22.1)	46.2	(3.7)	309.5	329.9
Balance, September 30, 2015	\$ (30.0)	\$ (378.5)	\$ (1.1)	\$ 391.9	\$ (17.7)

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 available-for- sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCL
For the nine months ended September 30, 2014					
Balance, January 1, 2014	\$ (4.2)	\$ (353.4)	\$ 2.4	\$ (74.9)	\$ (430.1)
Other comprehensive income (loss) before reclassifications	(7.9)	-	0.3	84.8	77.2
Amounts reclassified from accumulated other comprehensive income loss (gain)	1.5	27.2	-	-	28.7
Net current period other comprehensive income (loss)	(6.4)	27.2	0.3	84.8	105.9
Other	0.6	-	(0.1)	4.3	4.8
Balance, September 30, 2014	\$ (10.0)	\$ (326.2)	\$ 2.6	\$ 14.2	\$ (319.4)

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30		
	2015	2014	2015	2014	
	Affected line item in the Consolidated Statements of Income and Balance Sheets		Amounts reclassified from AOCL		
Losses (gain) on derivatives recognized as cash flow hedges					
Power and gas swaps	Non-regulated fuel for generation and purchased power	\$ 1.1	\$ 1.9	\$ (3.9)	(1.9)
Interest rate swaps	Income from equity investments	0.2	0.2	0.5	0.5
Foreign exchange forwards	Operating revenue – regulated	2.6	0.6	6.3	2.3
Total before tax		3.9	2.7	2.9	0.9
	Income tax expense (recovery)	(0.5)	(0.8)	1.4	0.6
Total net of tax		\$ 3.4	\$ 1.9	\$ 4.3	1.5
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses (gains)		\$ 12.8	\$ 9.0	\$ 36.9	29.7
Past service costs (gains)	OM&G	(2.2)	(0.6)	(5.0)	(1.8)
Amounts reclassified into obligations	Pension and post-retirement liabilities	(0.1)	-	23.4	-
Total before tax		10.5	8.4	55.3	27.9
	Income tax expense (recovery)	-	(0.1)	(9.1)	(0.7)
Total net of tax		\$ 10.5	\$ 8.3	\$ 46.2	27.2
Total reclassifications out of AOCL, net of tax, for the period		\$ 13.9	\$ 10.2	\$ 50.5	28.7

12. RESTRICTED CASH

Restricted cash consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Restricted cash – BLPC	\$ 14.6	\$ 14.9
Restricted cash – Brunswick Pipeline	3.9	-
Restricted cash – Other	1.1	1.0
	\$ 19.6	\$ 15.9

13. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Customer accounts receivable – billed	\$ 324.9	\$ 356.0
Customer accounts receivable – unbilled	118.7	141.1
Total customer accounts receivable	443.6	497.1
Allowance for doubtful accounts	(13.3)	(11.1)
Customer accounts receivable, net	430.3	486.0
Other	25.9	28.2
	\$ 456.2	\$ 514.2

14. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Fuel	\$ 163.3	\$ 185.7
Materials	95.5	87.9
Emission credits (1)	27.7	20.9
	\$ 286.5	\$ 294.5

(1)The New England Gas Generating Facilities are subject to the Acid Rain Program for sulphur dioxide emissions and the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions. In addition, Bridgeport Energy is subject to the Clean Air Interstate Rule for ozone season nitrogen dioxide emission allowances. The emissions credits inventory balance represents the credits purchased to offset the liabilities (note 23) associated with these programs.

15. 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 AOCL 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 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 held-for-trading ("HFT") derivatives and are recorded on the balance sheet at fair value, with changes normally recorded in net income of the period, unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

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

As at millions of Canadian dollars	Derivative Assets		Derivative Liabilities	
	September 30 2015	December 31 2014	September 30 2015	December 31 2014
Current				
<i>Cash flow hedges</i>				
Power swaps	\$ 7.6	\$ 8.4	\$ 0.5	0.5
Foreign exchange forwards	-	0.1	11.3	4.5
	7.6	8.5	11.8	5.0
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	-	7.9	5.4
Natural gas purchases and sales	-	0.8	0.5	1.4
Heavy fuel oil purchases	-	-	16.3	12.6
Foreign exchange forwards	81.1	36.0	6.5	-
Physical natural gas purchases and sales	3.0	0.1	-	-
	84.1	36.9	31.2	19.4
<i>HFT derivatives</i>				
Power swaps and physical contracts	107.1	138.1	61.1	74.1
Natural gas swaps, futures, forwards, physical contracts	104.6	86.4	154.1	162.3
	211.7	224.5	215.2	236.4
Total gross current derivatives	303.4	269.9	258.2	260.8
Impact of master netting agreements with intent to settle net or simultaneously	(130.2)	(133.4)	(130.2)	(133.4)
Total current derivatives	173.2	136.5	128.0	127.4
Long-term				
<i>Cash flow hedges</i>				
Power swaps	11.3	14.5	4.0	3.7
Foreign exchange forwards	0.3	-	24.5	10.5
	11.6	14.5	28.5	14.2
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	-	2.1	4.8
Heavy fuel oil purchases	-	-	15.6	12.9
Foreign exchange forwards	118.9	61.5	2.5	3.9
Physical natural gas purchases and sales	0.4	-	-	-
	119.3	61.5	20.2	21.6
<i>HFT derivatives</i>				
Power swaps and physical contracts	17.6	18.5	29.5	22.2
Natural gas swaps, futures, forwards and physical contracts	19.4	31.7	41.0	53.6
Foreign exchange options	0.1	-	2.6	-
	37.1	50.2	73.1	75.8
<i>Other derivatives</i>				
Interest rate swap	-	-	3.1	-
	-	-	3.1	-
Total gross long-term derivatives	168.0	126.2	124.9	111.6
Impact of master netting agreements with intent to settle net or simultaneously	(26.6)	(34.2)	(26.6)	(34.2)
Total long-term derivatives	141.4	92.0	98.3	77.4
Total derivatives	\$ 314.6	\$ 228.5	\$ 226.3	\$ 204.8

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

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

As at millions of Canadian dollars	Derivative Assets		Derivative Liabilities	
	September 30 2015	December 31 2014	September 30 2015	December 31 2014
Regulatory deferral	\$ -	\$ 0.7	\$ -	\$ 0.7
HFT derivatives	156.8	166.9	156.8	166.9
Total impact of master netting agreements with intent to settle net or simultaneously	\$ 156.8	\$ 167.6	\$ 156.8	\$ 167.6

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 AOCL, 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 AOCL consisted of the following:

For the millions of Canadian dollars	Three months ended September 30					
	2015			2014		
	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Unrealized gain (loss) in Non-regulated fuel for generation and purchased power – ineffective portion	\$ 0.2	\$ -	\$ -	\$ 2.4	\$ -	\$ -
Realized gain (loss) in Non-regulated fuel for generation and purchased power	(1.1)	-	-	(1.9)	-	-
Realized gain (loss) in Operating revenue – regulated	-	-	(2.6)	-	-	(0.6)
Realized gain (loss) in Income from equity investments	-	(0.2)	-	-	(0.2)	-
Total gains (losses) in Net income	\$ (0.9)	\$ (0.2)	\$ (2.6)	\$ 0.5	\$ (0.2)	\$ (0.6)

For the millions of Canadian dollars	Nine months ended September 30					
	2015			2014		
	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Unrealized gain (loss) in Non-regulated fuel for generation and purchased power – ineffective portion	\$ (0.1)	\$ -	\$ -	\$ 2.7	\$ -	\$ -
Realized gain (loss) in Non-regulated fuel for generation and purchased power	3.9	-	-	1.9	-	-
Realized gain (loss) in Operating revenue – regulated	-	-	(6.3)	-	-	(2.3)
Realized gain (loss) in Income from equity investments	-	(0.5)	-	-	(0.5)	-
Total gains (losses) in Net income	\$ 3.8	\$ (0.5)	\$ (6.3)	\$ 4.6	\$ (0.5)	\$ (2.3)

As at millions of Canadian dollars	September 30 2015			December 31 2014		
	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCL – effective portion, net of tax	\$ 3.2	\$ (1.1)	\$ (35.8)	\$ 5.2	\$ (1.4)	\$ (14.9)

The Company expects \$13.0 million of unrealized losses currently in AOCL to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at September 30, 2015, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2015	2016	2017	2018	2019
Power swaps (megawatt hours (“MWh”)) purchases	0.1	0.3	0.3	0.3	0.3
Foreign exchange forwards (USD) sales	\$ 10.5	\$ 53.4	\$ 53.4	\$ 32.8	\$ 18.0
Foreign exchange forwards (EURO) purchases	-	-	2.6	-	-

Regulatory Deferral

As previously noted, 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 millions of Canadian dollars	Three months ended September 30					
	2015			2014		
	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	\$ (14.2)	\$ -	\$ (3.1)	\$ (2.5)	\$ -	\$ 4.8
Unrealized gain (loss) in Regulatory liabilities	-	1.6	71.5	0.3	-	39.3
Realized (gain) loss in Regulatory assets	(1.0)	-	-	0.9	-	-
Realized (gain) loss in Inventory (1)	2.6	-	(10.6)	1.1	-	(3.3)
Realized (gain) loss in property, plant and equipment	-	-	-	-	-	0.2
Realized (gain) loss in Regulated fuel for generation and purchased power (2)	(1.9)	(2.5)	(5.4)	0.2	(1.0)	(1.4)
Total change in Derivative instruments	\$ (14.5)	\$ (0.9)	\$ 52.4	\$ -	\$ (1.0)	\$ 39.6

(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 Nine months ended September 30

	2015			2014		
	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	\$ (37.3)	\$ -	\$ (5.5)	\$ (7.5)	\$ -	\$ (2.3)
Unrealized gain (loss) in Regulatory liabilities	(0.1)	8.1	148.2	8.7	2.3	43.8
Realized (gain) loss in Regulatory assets	(0.2)	-	-	2.3	-	-
Realized (gain) loss in Inventory (1)	5.9	-	(30.3)	3.5	-	(10.7)
Realized (gain) loss in property, plant and equipment	-	-	(1.0)	-	-	0.3
Realized (gain) loss in Regulated fuel for generation and purchased power (2)	(4.7)	(4.9)	(14.0)	(13.7)	(2.1)	(4.0)
Total change in Derivative instruments	\$ (36.4)	\$ 3.2	\$ 97.4	\$ (6.7)	\$ 0.2	\$ 27.1

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

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

Commodity Swaps and Forwards

As at September 30, 2015, 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:

	2015	2016	2017	2018
millions	Purchases	Purchases	Purchases	Purchases
Coal (metric tonnes)	-	0.3	-	-
Heavy fuel oil (bbls)	0.1	0.3	0.2	0.1

Foreign Exchange Swaps and Forwards

As at September 30, 2015, 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:

	2015	2016	2017	2018	2019
Fuel purchases exposure (millions of US dollars)	\$ 50.3	\$ 199.0	\$ 222.0	\$ 143.0	\$ 96.5
Weighted average rate	1.0024	1.0235	1.0704	1.1053	1.1265
% of USD requirements	101%	79%	93%	68%	46%

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	
	2015	2014	2015	2014
Power swaps and physical contracts in non-regulated operating revenues	\$ 3.2	\$ -	\$ 7.2	\$ 5.1
Natural gas swaps, forwards, futures, physical contracts in non-regulated operating revenues	43.1	4.0	111.8	187.2
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for purchased power	0.7	(2.4)	(0.5)	(5.4)
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	(4.8)	-	(7.5)	-
Foreign exchange options in non-regulated operating revenue	(2.0)	-	(2.6)	-
	\$ 40.2	\$ 1.6	\$ 108.4	\$ 186.9

As at September 30, 2015, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2015	2016	2017	2018	2019
Natural gas purchases (Mmbtu)	58.3	182.6	66.8	43.8	43.8
Natural gas sales (Mmbtu)	34.6	97.5	29.7	5.2	5.2
Power purchases (MWh)	0.1	0.3	0.3	0.3	0.3
Power sales (MWh)	0.8	1.1	-	-	-
Foreign exchange options (USD)	\$ 5.1	\$ 19.5	\$ 7.5	-	-
Foreign exchange forwards (EURO) purchases	0.5	-	0.2	-	-
Foreign exchange forwards (EURO) sales	0.2	-	-	-	-

Other Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to an interest rate swap:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Unrealized gain (loss) in Interest expense, net	\$ (1.2)	\$ -	\$ (3.1)	\$ -
Total gains (losses) in Net income	\$ (1.2)	\$ -	\$ (3.1)	\$ -

As at September 30, 2015, the Company had interest rate swaps in place for the \$250 million non-revolving term credit facility in Brunswick Pipeline for interest payments until the debt matures in 2019.

Credit Risk

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

The Company assesses the potential for credit losses on a regular basis, and where appropriate, 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, 2015, the Company had \$86.9 million (December 31, 2014 - \$79.9 million) in financial assets, considered to be past due, which have been outstanding for an average 82 days. The fair value of these financial assets is \$75.5 million (December 31, 2014 - \$70.3 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, 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 2015	December 31 2014
Cash collateral provided to others	\$ 37.4	\$ 45.8
Cash collateral received from others	1.5	2.9

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 of the Company's 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, 2015, the total fair value of these derivatives, in a liability position, was \$226.3 million (December 31, 2014 - \$204.8 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 15), 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, 2015			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Cash flow hedges</i>				
Power swaps	\$ 18.9	\$ -	\$ -	\$ 18.9
Foreign exchange forwards	-	0.3	-	0.3
	18.9	0.3	-	19.2
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Foreign exchange forwards	-	200.0	-	200.0
Physical natural gas purchases and sales	-	-	3.3	3.3
	-	200.0	3.3	203.3
<i>HFT derivatives</i>				
Power swaps and physical contracts	39.9	-	0.7	40.6
Foreign exchange options	-	0.2	-	0.2
Natural gas swaps, futures, forwards, physical contracts and related transportation	-	23.1	28.2	51.3
	39.9	23.3	28.9	92.1
Total assets	58.8	223.6	32.2	314.6
Liabilities				
<i>Cash flow hedges</i>				
Power swaps	4.4	-	-	4.4
Foreign exchange forwards	-	35.9	-	35.9
	4.4	35.9	-	40.3
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	10.0	-	10.0
Heavy fuel oil purchases	-	31.9	-	31.9
Natural gas purchases and sales	0.5	-	-	0.5
Foreign exchange forwards	-	9.0	-	9.0
	0.5	50.9	-	51.4
<i>HFT derivatives</i>				
Power swaps and physical contracts	6.3	-	0.4	6.7
Foreign exchange options	-	2.6	-	2.6
Natural gas swaps, futures, forwards and physical contracts	13.2	8.0	101.0	122.2
	19.5	10.6	101.4	131.5
<i>Other derivatives</i>				
Interest rate swap	-	3.1	-	3.1
	-	3.1	-	3.1
Total liabilities	24.4	100.5	101.4	226.3
Net assets (liabilities)	\$ 34.4	\$ 123.1	\$ (69.2)	\$ 88.3

As at	December 31, 2014			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Cash flow hedges</i>				
Power swaps	\$ 14.2	\$ -	\$ 8.7	\$ 22.9
Foreign exchange forwards	-	0.1	-	0.1
	14.2	0.1	8.7	23.0
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Natural gas purchases and sales	0.1	-	-	0.1
Foreign exchange forwards	-	97.5	-	97.5
Physical natural gas purchases and sales	-	-	0.1	0.1
	0.1	97.5	0.1	97.7
<i>HFT derivatives</i>				
Power swaps and physical contracts	66.3	-	(3.4)	62.9
Natural gas swaps, futures, forwards and physical contracts	(1.8)	22.3	24.4	44.9
	64.5	22.3	21.0	107.8
Total assets	78.8	119.9	29.8	228.5
Liabilities				
<i>Cash flow hedges</i>				
Power swaps	\$ 1.0	\$ -	\$ 3.2	\$ 4.2
Foreign exchange forwards	-	15.0	-	15.0
	1.0	15.0	3.2	19.2
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	10.2	-	10.2
Natural gas purchases and sales	0.7	-	-	0.7
Heavy fuel oil purchases	-	25.5	-	25.5
Foreign exchange forwards	-	3.9	-	3.9
	0.7	39.6	-	40.3
<i>HFT derivatives</i>				
Power swaps and physical contracts	1.3	-	1.5	2.8
Natural gas swaps, futures, forwards and physical contracts	13.5	12.0	117.0	142.5
	14.8	12.0	118.5	145.3
Total liabilities	16.5	66.6	121.7	204.8
Net assets (liabilities)	\$ 62.3	\$ 53.3	\$ (91.9)	\$ 23.7

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, 2015, transfers from Level 3 to Level 1 were a result of an increase in observable inputs.

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2015 was as follows:

millions of Canadian dollars	<i>Regulatory Deferral</i>		<i>Cash Flow Hedges and HFT Derivatives</i>		Total
	Physical natural gas purchases and sales		Power	Natural gas	
Balance, beginning of period	\$ 4.2	\$	\$ 0.9	\$ 30.2	\$ 35.3
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	(2.5)		-	-	(2.5)
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	1.6		-	-	1.6
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-		(0.2)	(2.0)	(2.2)
Balance, September 30, 2015	\$ 3.3	\$	\$ 0.7	\$ 28.2	\$ 32.2

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2015 was as follows:

millions of Canadian dollars	<i>Regulatory Deferral</i>		<i>Cash Flow Hedges and HFT Derivatives</i>		
	Physical natural gas purchases and sales		Power	Natural gas	Total
Balance, beginning of period	\$ -	\$ -	0.4	\$ 120.3	\$ 120.7
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	-	-	(19.3)	(19.3)
Balance, September 30, 2015	\$ -	\$ -	0.4	\$ 101.0	\$ 101.4

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2015 was as follows:

millions of Canadian dollars	<i>Regulatory Deferral</i>		<i>Trading Derivatives</i>		
	Physical natural gas purchases and sales		Power	Natural gas	Total
Balance, beginning of period	\$ 0.1	\$ 5.3	\$ 24.4	\$ 29.8	\$ 29.8
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	(4.9)	-	-	-	(4.9)
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	8.1	-	-	-	8.1
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	(0.3)	3.8	3.5	3.5
Net transfers out of Level 3	-	(4.3)	-	(4.3)	(4.3)
Balance, September 30, 2015	\$ 3.3	\$ 0.7	\$ 28.2	\$ 32.2	\$ 32.2

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2015 was as follows:

millions of Canadian dollars	<i>Regulatory Deferral</i>		<i>Trading Derivatives</i>		
	Physical natural gas purchases and sales		Power	Natural gas	Total
Balance, beginning of period	\$ -	\$ 4.7	\$ 117.0	\$ 121.7	\$ 121.7
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	-	4.4	-	4.4	4.4
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	-	(16.0)	(16.0)	(16.0)
Net transfers out of Level 3	-	(8.7)	-	(8.7)	(8.7)
Balance, September 30, 2015	\$ -	\$ 0.4	\$ 101.0	\$ 101.4	\$ 101.4

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, 2015				
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
<i>Regulatory deferral – Physical natural gas purchases and sales</i>	3.3	Modelled pricing	Third-party pricing	\$3.98 - \$6.11	\$4.84
			Probability of default	0.05%	0.05%
<i>HFT derivatives – Power swaps and physical contracts</i>	0.7	Modelled pricing	Third-party pricing	\$16.87 - \$90.14	\$54.23
			Correlation factor	0.99% - 1.00%	0.99%
			Probability of default	0.01% - 0.17%	0.03%
			Discount rate	0.00% - 15.66%	7.39%
<i>HFT derivatives – Natural gas swaps, futures, forwards,</i>	28.2	Modelled pricing	Third-party pricing	\$0.86 - \$9.62	\$5.28
			Probability of default	0.01% - 10.6%	1.59%
			Discount rate	0.00% - 65.54%	3.23%
Total assets	32.2				
Liabilities					
<i>HFT derivatives – Power swaps and physical contracts</i>	0.3	Modelled pricing	Third-party pricing	\$16.87 - \$90.14	\$55.68
			Correlation factor	0.99% - 1.0%	0.99%
			Own credit risk	0.01% - 0.01%	0.01
			Discount rate	0.00% - 15.66%	7.88%
	0.1	Modelled pricing	Third-party pricing	\$47.22- \$77.70	\$58.65
			Own credit risk	0.01% - 0.01%	0.01
			Discount rate	0.00% - 0.34%	0.04%
<i>HFT derivatives – Natural gas swaps, futures, forwards and</i>	101.0	Modelled pricing	Third-party pricing	\$0.86- \$9.69	\$3.98
			Probability of default	0.01% - 0.01%	0.01%
			Discount rate	0.00% - 38.56%	3.11%
Total liabilities	101.4				
Net assets (liabilities)	\$ (69.2)				

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

As at	September 30, 2015		December 31, 2014	
millions of Canadian dollars	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including current portion)	\$ 3,771.3	\$ 4,260.7	\$ 3,754.8	\$ 4,382.9

The fair values of long-term debt instruments, classified as level 3 in the fair value hierarchy, are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

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.

17. 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 2014 annual audited consolidated financial statements.

As at millions of Canadian dollars	September 30 2015	December 31 2014
Regulatory assets		
Deferred income tax regulatory asset	\$ 391.9	\$ 348.1
Deferrals related to derivative instruments	58.6	45.6
Unamortized defeasance costs	47.4	52.5
Stranded cost recovery	27.8	24.9
Demand side management deferral (note 5)	27.1	-
Pension and post-retirement medical plan	12.6	10.4
Hydro-Quebec obligation	7.6	6.8
Stranded cost revenue & purchase power reconciliation deferrals	6.4	8.0
Purchase power contracts	6.3	7.0
2014 Maine storms	5.8	5.3
Asset impairment recovery	5.4	4.8
2013 Maine ice storm	4.8	5.0
Earnings Share Mechanism	4.5	4.9
Large industrial customers fixed cost deferral	4.0	15.8
Regulated fuel adjustment mechanism (note 5)	-	47.9
Other	25.1	23.7
	\$ 635.3	\$ 610.7
Current	\$ 74.6	115.0
Long-term	560.7	495.7
Total regulatory assets	\$ 635.3	\$ 610.7
Regulatory liabilities		
Deferrals related to derivative instruments	\$ 203.3	\$ 97.7
Self-Insurance Fund	84.0	72.8
Deferred income tax regulatory liabilities	32.8	25.7
Regulated fuel adjustment mechanism (note 5)	8.3	-
Maine Federal Energy Regulatory Commission return on equity	8.1	8.5
Other	7.8	5.2
	\$ 344.3	\$ 209.9
Current	\$ 114.9	51.0
Long-term	229.4	158.9
Total regulatory liabilities	\$ 344.3	\$ 209.9

18. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its associated and other related companies on terms similar to those offered to non-related parties.

If these transactions are eliminated on consolidation, they are not disclosed as related party transactions. Below are transactions between Emera and its associated companies that are not eliminated on consolidation:

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30		
		2015	2014	2015	2014	
Nature of Service		Presentation				
Sales:						
Emera Utility Services	Maintenance and construction services	Operating revenue – non-regulated	\$ 6.7	\$ 5.8	\$ 15.7	11.5
Emera Energy	Net sale of natural gas and sale of power	Operating revenue – non-regulated	4.0	4.5	11.6	10.6
Emera Energy	Hedging services	Operating revenue – non-regulated and interest expense, net	4.8	-	11.5	-
EUS Bahamas	Construction, operations management and engineering services	Operating revenue – non-regulated	2.7	2.8	7.5	6.9
Emera Energy	Sale of natural gas and transportation (3)	Operating revenue – non-regulated	-	0.2	1.6	4.3
Emera Energy	Energy management services (1)	Operating revenue – non-regulated	-	-	-	0.2
Emera Maine	Transmission capacity (1)	Operating revenue – regulated	-	0.2	0.3	0.8
Purchases:						
NSPI	Construction services	Property, plant and equipment	6.7	4.9	14.0	9.7
NSPI	Net purchase of natural gas and purchase of power	Regulated fuel for generation and purchased power	4.0	4.5	11.6	10.6
GBPC	Hedging services	Regulated fuel for generation and purchased power and OM&G	4.8	-	11.5	-
GBPC	Maintenance services	OM&G	2.7	2.8	7.2	6.3
NSPI	Natural gas transportation capacity (2)	Regulated fuel for generation and purchased power	1.7	1.0	3.7	3.2
NSPI	Maintenance services	OM&G	0.1	0.9	1.8	1.8
GBPC	Construction services	Property, plant and equipment	-	-	0.3	0.6
Emera Maine	Purchase of power (1)	Regulated fuel for generation and purchased power	-	0.4	0.3	1.4
Emera Energy	Natural gas transportation capacity (2)	Operating revenue – non-regulated	(5.5)	(5.5)	(16.8)	(18.6)

(1) Transactions with NWP which was a related party accounted for under the equity method until its sale on January 29, 2015.

(2) Transactions with M&NP, a related party accounted for under the equity method.

(3) Transactions with a subsidiary of APUC, a related party accounted for under the equity method.

Amounts due (to) from Emera and its equity investments are summarized in the following table:

As at millions of Canadian dollars		September 30 2015	December 31 2014
Due from related parties:			
NSPML – current	\$	1.4	\$ 3.5
M&NP – loan receivable – long-term		2.5	2.5
Due to related parties:			
M&NP – current	\$	(1.7)	\$ (1.6)
Net due from (to) related parties	\$	2.2	\$ 4.4

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.

19. OTHER CURRENT ASSETS

Other current assets consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Net investment in direct financing lease	\$ 5.3	\$ 5.1
Dividend receivable	6.5	5.0
Capitalized transportation capacity	21.1	70.5
	\$ 32.9	\$ 80.6

20. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Maine, Connecticut, Rhode Island, Barbados, Dominica and Grand Bahama Island.

Effective April 1, 2015, Emera Maine amended certain post-retirement medical benefits which resulted in a reduction in the pension and post-retirement benefits liability.

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2015	2014	2015	2014
Defined benefit pension plans				
Service cost	\$ 5.5	\$ 4.3	\$ 16.5	\$ 12.9
Interest cost	14.7	15.4	43.9	46.2
Expected return on plan assets	(16.2)	(15.8)	(48.3)	(47.3)
Current year amortization of:				
Actuarial losses (gains)	11.9	9.0	35.5	26.9
Past service costs (gains)	(0.2)	(0.2)	(0.6)	(0.6)
Special termination benefits	-	(0.1)	-	-
Total defined benefit pension plans	15.7	12.6	47.0	38.1
Non-pension benefits plan				
Service cost	0.7	0.7	2.2	2.1
Interest cost	0.8	1.1	2.6	3.2
Expected return on plan assets	(0.1)	(0.1)	(0.2)	(0.3)
Current year amortization of:				
Actuarial losses (gains)	0.5	-	1.2	-
Past service costs (gains)	(2.0)	(0.4)	(4.4)	(1.2)
Total non-pension benefits plans	(0.1)	1.3	1.4	3.8
Total defined benefit plans	\$ 15.6	\$ 13.9	\$ 48.4	\$ 41.9

Emera's contributions related to these defined-benefit plans for the three months ended September 30, 2015 were \$5.3 million (2014 – \$16.8 million), and for the nine months ended September 30, 2015 were \$22.6 million (2014 – \$40.5 million).

In addition, the Company contributions related to the defined contribution plan for the three months ended September 30, 2015 were \$2.2 million (2014 – \$2.5 million), and for the nine months ended September 30, 2015 were \$7.0 million (2014 – \$6.7 million).

21. AVAILABLE-FOR-SALE INVESTMENTS

The available-for-sale investments consist primarily of debt and equity investments held in trust on behalf of BLPC's Self Insurance Fund ("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.

In addition, there are debt and equity investments related to Emera Reinsurance Limited, for captive insurance purposes.

Emera has classified these investments as available-for-sale and recorded all such investments at their fair market value as at September 30, 2015.

Available-for-sale financial assets measured at fair value include the following:

As at millions of Canadian dollars	Level 1	Level 2	Level 3	September 30 2015
Common shares	\$ 15.1	\$ -	\$ -	15.1
Mutual funds	-	50.3	-	50.3
Corporate bonds, debentures, short and medium term notes	-	41.7	-	41.7
Government bonds	-	3.3	-	3.3
	\$ 15.1	\$ 95.3	\$ -	110.4

As at millions of Canadian dollars	Level 1	Level 2	Level 3	December 31 2014
Common shares	\$ 13.8	\$ -	\$ -	13.8
Mutual funds	-	31.7	-	31.7
Corporate bonds, debentures, short and medium term notes	-	36.1	-	36.1
Government bonds	-	2.8	-	2.8
	\$ 13.8	\$ 70.6	\$ -	84.4

The fair value of financial instruments traded in active markets is based on quoted market prices at the balance sheet date for level 1 available for sale investments. The quoted market price used for financial assets is the current bid price at the balance sheet date. Fair values within the level 2 category are determined through the use of quoted prices in active markets for similar assets, which in some cases, are adjusted for factors specific to the asset.

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

As at millions of Canadian dollars	September 30 2015	December 31 2014
Balance, beginning of the year	\$ 84.4	\$ 74.2
Additions	21.9	30.3
Disposals	(4.4)	(27.1)
	\$ 101.9	\$ 77.4
<i>Change in fair value</i>		
Realized (loss) gain recognized in income	-	(0.8)
Gain (loss) recognized in other comprehensive income during the period	8.5	7.8
	\$ 8.5	\$ 7.0
Balance, end of the period	\$ 110.4	\$ 84.4

There were no impairment provisions for available-for-sale investments for the nine months ended September 30, 2015 (2014 - nil).

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

As at millions of Canadian dollars	September 30 2015	December 31 2014
Maturity within 1 year	\$ 18.4	\$ 12.8
Maturity in 1-5 years	26.6	26.1
	\$ 45.0	\$ 38.9

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.

22. OTHER LONG-TERM ASSETS

Other long term assets consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Subscription receipts	\$ 116.1	\$ 111.7
Deferred debt financing (1)	64.8	23.0
Capitalized transportation capacity	29.8	31.8
Open Hydro investment	10.0	10.0
Equipment financing receivable	25.0	20.5
Other	9.4	8.3
	\$ 255.1	\$ 205.3

(1) As at September 30, 2015, the deferred debt financing asset includes \$40.2 million related to the \$1.9 billion in Debentures to finance a portion of the pending TECO Energy acquisition. The deferred debt financing costs related to the Debentures are being amortized over 10 years, the contractual term of the debentures, in Interest expense, net.

23. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Accrued charges	\$ 111.3	\$ 114.1
Accrued interest on long-term debt	41.3	42.4
Emission credits obligations (1)	4.4	20.6
Sales taxes payable	7.5	5.6
Dividends payable	78.2	2.0
Other	8.7	2.1
	\$ 251.4	\$ 186.8

(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 14) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

24. SHORT-TERM DEBT

Credit Facilities

For the purpose of bridge financing for the pending acquisition of TECO Energy, on September 4, 2015, the Company secured an aggregate of \$6.5 billion USD non-revolving term credit facilities the ("Acquisition Credit Facilities") from a syndicate of banks. The non-revolving term credit facilities are comprised of a \$4.3 billion USD debt bridge facility, repayable in full on the first anniversary following its advance, and a \$2.2 billion USD equity bridge facility repayable in full on the first anniversary following its advance.

Emera is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common equity, preferred equity, bond or other debt offerings and any non-ordinary course asset sales by Emera and its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Debenture Offering, or from any such non-ordinary course asset sales or transactions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn.

The credit agreements pursuant to which the Acquisition Credit Facilities will be extended (the "Acquisition Credit Agreements") will contain certain prepayment options in favour of Emera and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Emera and certain of its subsidiaries (other than certain permitted equity or debt offerings subject to certain prescribed exceptions) and of any non-ordinary course asset sales (subject to certain prescribed exceptions) and certain other prescribed transactions will be required to be used to prepay the Acquisition Credit Facilities. In addition, any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements will contain customary representations and warranties and affirmative and negative covenants of Emera that will closely resemble those in Emera's existing revolving credit facility.

Emera has recognized the costs associated with the bridge fees related to the Acquisition Credit Facilities in "Operating, maintenance and general" on Emera's Consolidated Statements of Income.

25. LONG-TERM DEBT

NSPI

On April 30, 2015, NSPI completed the issuance of \$175 million Series AA Medium-Term Notes ("MTN"). The Series AA notes bear interest at a rate of 3.612 per cent per annum until May 1, 2045. The proceeds of the note offering were used for general corporate purposes, including the repayment of maturing corporate term debt.

NSPI Series I \$70 million 8.40 per cent MTN matured on October 23, 2015.

Brunswick Pipeline

On February 18, 2015, Brunswick Pipeline completed a senior secured financing consisting of a \$250 million non-revolving term credit facility bearing interest at bankers' acceptance rates plus 1.75 per cent and expiring on February 18, 2019. The proceeds were used to reduce borrowings under Emera's revolver, which was previously used to finance the maturity and repayment of a MTN note in October 2014.

26. CONVERTIBLE DEBENTURES REPRESENTED BY INSTALMENT RECEIPTS

To finance a portion of the pending acquisition of TECO Energy, on September 28, 2015, 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 (the "Debentures" or the "Debenture Offering").

The Debentures were sold on an instalment basis at a price of \$1,000 per Debenture, of which \$333 was paid on closing of the Debenture Offering and the remaining \$667 (the "Final Instalment") is payable on a date ("Final Instalment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of TECO Energy.

Prior to the Final Instalment Date, the Debentures are represented by instalment receipts. The instalment receipts began trading on the Toronto Stock Exchange ("TSX") on September 28, 2015 under the symbol "EMA.IR". The Debentures will not be listed. The Debentures will mature on September 29, 2025 and bear interest at an annual rate of four per cent per \$1,000 principal amount of Debentures until and including the Final Instalment Date, after which the interest rate will be 0 per cent. Based on the first instalment of \$333 per \$1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12 per cent, and the effective annual yield thereafter is 0 per cent.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final instalment on or before the Final

Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Under the terms of the instalment receipt agreement, Emera agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Company will at all times hold (on a consolidated basis) short-term USD investment grade securities or have cash on hand of not less than the aggregate amount of the first instalment paid on the closing of the Debenture Offering and the exercise of the over-allotment option, in the event of a mandatory redemption.

Approximately \$0.6 million (\$0.4 million after-tax) in interest expense associated with the Debentures was recognized in Q3 2015 and a total of approximately \$19.8 million (\$13.7 million after-tax) is expected to be incurred in 2015 (note 7).

At the option of the holders and provided that payment of the Final Instalment has been made, each Debenture will be 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, subject to adjustment in certain events.

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Company, except that Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions precedent to the closing of the acquisition of TECO Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) April 24, 2017, if notice of the Final Instalment Date has not been given to holders on or before April 21, 2017. Upon any such redemption, the Company will pay for each Debenture: (i) \$333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) \$667 to the Selling Debentureholder on behalf of the holder of the instalment receipt in satisfaction of the Final Instalment. In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by Emera at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date.

At maturity, Emera will have the right to pay the principal amount due in common shares, which will be valued at 95 per cent of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment of the Debenture Offering were \$632.7 million, or \$592.5 million net of issue costs and will be held and invested in short-term USD investment grade securities. The convertible debentures represented by instalment receipts are classified as a current liability on the Consolidated Balance Sheets as the pending acquisition of TECO Energy is expected to close in fiscal 2016.

The net proceeds of the final instalment payment of the Debenture Offering are expected to be, in aggregate, approximately \$1.4 billion and will be used, together with the net proceeds of the first instalment payment, to finance, directly or indirectly, the acquisition of TECO Energy and other acquisition related costs.

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2015, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures represented by instalment receipts, long-term debt and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2015	2016	2017	2018	2019	Thereafter	Total
Purchased power (1)	\$ 52.9	\$ 219.9	\$ 230.4	\$ 204.9	\$ 199.7	\$ 2,545.2	\$ 3,453.0
Coal, biomass, oil and natural gas supply	50.8	164.5	71.7	0.5	-	-	287.5
Transportation (2)	33.3	104.6	61.8	47.0	24.9	106.1	377.7
Long-term service agreements (3)	21.6	53.1	42.8	31.7	53.3	218.3	420.8
Capital projects	49.9	36.6	5.6	0.1	-	-	92.2
Equity investment commitments (4)	113.1	330.2	159.3	-	-	-	602.6
Leases and other (5)	10.1	11.9	11.3	9.2	8.7	33.5	84.7
	\$ 331.7	\$ 920.8	\$ 582.9	\$ 293.4	\$ 286.6	\$ 2,903.1	\$ 5,318.5

(1) Purchased power: annual requirement to purchase 20 - 100 per cent of electricity production from independent power producers over varying contract lengths up to 25 years.

(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.

(3) Long-term service agreements: 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 amount as the projects advance through construction.

(5) Leases: 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 October 12, 2015, purported shareholders of TECO Energy filed eleven separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida.

Each complaint alleges that the board of directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and seeks to enjoin the merger pursuant to the acquisition agreement. In addition, (i) seven of the complaints allege that TECO Energy, Emera and Emera US Inc. aided and abetted such alleged breaches; (ii) three other complaints allege Emera and Emera US Inc. aided and abetted such alleged breaches; and (iii) one other complaint alleges that Emera aided and abetted such alleged breaches. The complaints were subsequently amended to include allegations that the preliminary proxy statement in relation to the merger filed by TECO Energy on October 6, 2015 fails to disclose certain material information.

The court has scheduled a hearing to be held on November 20, 2015, on the plaintiffs' anticipated motion for a preliminary injunction.

On November 2, 2015, a purported shareholder of TECO Energy filed a complaint styled as a class action lawsuit in the United States District Court for the Middle District of Florida. This complaint alleges that the board of directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition and seeks to enjoin the merger pursuant to the acquisition agreement. In addition, the complaint alleges that Emera and Emera US Inc. aided and abetted such alleged breaches. The complaint further alleges that the preliminary proxy statement and the definitive proxy statement in relation to the merger, filed by TECO

Energy on October 6, 2015 and October 22, 2015, respectively, fail to disclose certain material information.

At this time, the outcome of the lawsuits cannot be predicted with any certainty. A preliminary injunction could delay or jeopardize the completion of the transaction, and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Emera believes that the claims asserted against the defendants in the lawsuits are without merit.

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 Open Access Transmission Tariff ("OATT") was unjust and unreasonable. On June 19, 2014, the FERC issued an order in connection with this complaint, changing the methodology used to set the ROE for transmission assets.

This change would lower the base transmission ROE to 10.57 per cent for the period of October 1, 2011 to December 31, 2012, subject to a further proceeding to finalize the determination of appropriate rates to be used in such calculation. The FERC decision would also lower the cap on the total ROE (inclusive of incentive adders) for transmission assets to 11.74 per cent. In an order issued on October 16, 2014, the FERC confirmed that the ROE set in its earlier order was appropriate. On March 3, 2015, in response to requests for rehearing from several parties, FERC affirmed its initial Order, setting of the base ROE of 10.57 per cent and capping the total ROE, including the effect of incentive adders, at 11.74 per cent. Notices of Appeal to the U.S. Court of Appeals for the DC Circuit were filed by New England Transmission Owners and the Complainants in the case on April 30, 2015. In Q2 2015, Emera Maine began processing the refunds to customers, based on a 10.57 per cent ROE. By court order dated August 20, 2015, the DC Court of Appeals decided to hold the appeal of this case in abeyance pending the outcome of the consolidated cases ("ENE Case" and "MA AG II Case") discussed below.

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"). On June 19, 2014, the FERC issued an order in this second ROE case, finding in favour of the complainants and allowing the complaint to proceed. As a result, a new ROE will be calculated and set by the FERC. This complaint created a new 15-month refund period beginning January 1, 2013 through 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 alleging the ROE earned on transmission investments is unjust and unreasonable and does not reflect current economic conditions ("the MA AG II Case"). Any potential refund arising from this third complaint will relate to the period from July 31, 2014 to September 30, 2015, and the outcome will set the ROE going forward from the date of decision.

On November 24, 2014, the FERC consolidated the ENE Case and MA AG II Case. A subsequent order by the FERC established a schedule for various procedural matters that turned the case over to an Administrative Law Judge in September 2015. Once that judge's recommended decision is rendered, parties may file exceptions, and then the case is set for decision by the FERC. A decision is therefore not expected until Q1 2016 at the earliest.

Emera Maine has recorded a reserve of \$8.2 million pre-tax (\$6.1 million USD) for the two outstanding base transmission ROE rate refund complaints for the period of October 1, 2011 to September 30, 2015, which are pending final determination by the FERC. .

Other Legal Proceedings

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

C. 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 \$45.3 million during fiscal 2015 and are estimated to be \$63.9 million from 2016 through 2019. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 27A. 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.

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.

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, 2015.

Emera Energy Emissions

The New England Gas Generating Facilities are subject to the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions and the Acid Rain Program for sulphur dioxide emissions. The New England Gas Generating 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.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol ("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 do not meet 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 \$36.0 million and, as at September 30, 2015, approximately \$18.5 million (December 31, 2014 – \$14.8 million) has been spent to date. NSPI has recognized an ARO of \$11.3 million as at September 30, 2015 (December 31, 2014 – \$11.8 million) associated with the PCB phase-out program.

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, 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. In addition, 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: APUC, M&NP, NSPML, LIL 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.

In November 2014, the Federal Energy Regulatory Commission ("FERC") commenced an audit of Bangor Hydro Electric Company's compliance with conditions established in FERC's orders authorizing its acquisition of Maine Public Service Company, which occurred on January 1, 2014. These two predecessor companies formed Emera Maine. The audit is currently ongoing, and a report of the FERC's findings is expected to be released in the last quarter of 2015 or the first quarter of 2016.

Brunswick Pipeline entered into a 25-year firm service agreement with Repsol Energy Canada, which was filed with the NEB. The firm service agreement provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the NEB on a complaint basis. Brunswick Pipeline is required to make copies of tariffs and supporting financial information readily available to interested persons. Persons who cannot resolve traffic, toll and tariff issues with Brunswick Pipeline may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

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 customers.

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.

Labour Risk

Certain Emera employees are subject to collective labour agreements; 51 per cent of the full-time and term employees within the Emera group of companies are represented by local unions.

Approximately 8 per cent of Emera's work force is included in collective labour agreements which will expire within the next 12 months.

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.

The Company is subject to interest rate risk relating to certain sources of expected funds to effect the TECO Energy acquisition. Any movement in interest rates could affect the underlying cost of the instrument used to fund the acquisition. The Company may enter into interest rate hedging contracts to limit its exposure to fluctuations in interest rates.

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.

The cash consideration for the TECO Energy acquisition is required to be paid in US dollars, a portion of which will be raised in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar will increase the purchase price translated in Canadian dollars and thereby increase the Canadian dollars required to fund the USD purchase price for the acquisition ultimately obtained by the Company.

The proceeds of the first instalment of the Debenture Offering were invested in short-term US dollar investment grade securities.

During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the second instalment of the Debenture Offering of the pending TECO Energy acquisition of \$1.457 billion. These foreign exchange forward contracts are economic hedges and do not qualify for hedge accounting. Therefore, all mark-to-market gains and losses will be recognized in net income for the period. In addition, 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

Emera had outstanding the following guarantees and letters of credit on behalf of third parties which are not included within the Consolidated Balance Sheets as at September 30, 2015:

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. ("RESL") under a \$23.5 million loan agreement between RESL and a third-party lender. As at September 30, 2015, RESL's indebtedness under the loan agreement was \$17.5 million. As security for RESL's indemnity obligations to NSPI in respect of the guarantee, NSPI holds a security interest in the present and future assets owned by RESL in connection with a wind energy project at Point Tupper, Nova Scotia. For further information, see Note 31.
- Emera has provided a completion guarantee to the Government of Canada, whereby it has guaranteed the performance of the obligations of NSPML to cause the completion of the Maritime Link Project, subject to certain conditions set out in that guarantee. The cost of those obligations is estimated to be \$1.577 billion.

- Emera has provided a guarantee to the Long Island Power Authority (“LIPA”) on behalf of Bear Swamp for Bear Swamp’s long-term energy and capacity supply agreement (“PPA”) with LIPA, which expires on April 30, 2021. The guarantee is for 50 per cent of the relevant obligations under the PPA up to a maximum of \$5.1 million USD. As at September 30, 2015, the fair value of the PPA was positive.
- Standby letters of credit in the amount of \$9.2 million USD for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.
- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2016 and is renewed annually. The amount committed as at September 30, 2015 was \$42.6 million.
- A standby letter of credit to secure obligations under an unfunded pension plan in Emera Maine. The letter of credit expires in October 2015 and is renewed annually. The amount committed as at September 30, 2015 was \$2.2 million USD.
- A standby letter of credit was issued to secure the obligations of Emera Reinsurance Limited under reinsurance agreements. The letter of credit expires in February 2016. The amount committed as at September 30, 2015 was \$2.0 million USD.
- NSPI has standby letters of credit in the amount of \$0.8 million, the majority of which cover an Abandonment Reclamation Agreement related to a lease with the Province of Nova Scotia. These letters of credit have a one-year term and are renewed annually as required.

28. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars
Balance, December 31, 2014	143.78	\$ 2,016.4
Issued for cash under Purchase Plans at market rate	1.50	62.9
Discount on shares purchased under Dividend Reinvestment Plan	-	(2.9)
Options exercised under senior management share option plan	0.05	1.5
Stock-based compensation	-	0.6
Balance, September 30, 2015	145.33	\$ 2,078.5

29. CUMULATIVE PREFERRED STOCK

On July 3, 2015, Emera announced it would not redeem the 6,000,000 Cumulative 5-Year Rate Reset First Preferred Shares, Series A Shares (“the Series A Shares”). On August 17, 2015, Emera announced that 2,135,364 of its 6,000,000 issued and outstanding Series A Shares were tendered for conversion, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series B (the “Series B Shares”). As a result of the conversion, Emera has 3,864,636 Series A Shares and 2,135,364 Series B Shares issued and outstanding. The holders of Series B Shares will be entitled to receive floating rate cumulative preferred cash dividends, as and when declared by the Board of Directors. The dividends are payable quarterly in the amount per share determined by multiplying the applicable quarterly floating dividend rate, which is the sum of the three-month Government of Canada T-bill Rate on the applicable reset date plus 1.84 per cent, by \$25.00.

30. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars	September 30 2015	December 31 2014
Preferred shares of NSPI (1)	\$ 132.2	\$ 132.2
ECI	118.8	99.6
ICDU	50.0	40.9
Preferred shares of GBPC	33.5	33.5
Preferred shares of Emera Maine	0.4	0.4
	\$ 334.9	\$ 306.6

(1) On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of \$25.00 per share.

31. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any variable interest entities (“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 or the right to receive benefits from 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, 2015, the Company has identified the following significant VIEs:

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera was 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 power over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link Project. Thus, Emera began recording the Maritime Link Project as an equity investment.

ECI 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.

NSPI holds a variable interest in RESL, a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. NSPI has provided a guarantee for the indebtedness of RESL under a loan agreement between RESL and a third-party lender for \$23.5 million, in support of which NSPI holds a security interest in the present and future assets owned by RESL in connection with a wind energy project at Point Tupper, Nova Scotia. The guarantee arose in conjunction with NSPI’s participation in the foregoing wind energy project, which is being operated by RESL. Under a purchased power agreement, NSPI purchases, at a fixed price, 100 per cent of the power generated by the project. A default by RESL, under its loan agreement, would require NSPI to make payment under the guarantee. As at September 30, 2015, RESL’s indebtedness under the loan

agreement was \$17.5 million (December 31, 2014 – \$18.4 million), and NSPI has not recorded a liability in relation to the guarantee.

The Company has identified certain long-term purchase power agreements that could be defined as 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.

Emera's consolidated VIE is recorded in "Available-for-sale investment" and "Restricted cash". The following table provides information about Emera's portion of consolidated and unconsolidated VIEs:

As at	September 30, 2015		December 31, 2014	
	Total	Maximum	Total	Maximum
millions of Canadian dollars	assets	exposure to loss	assets	exposure to loss
Consolidated VIE				
BLPC SIF	\$ 96.0	\$ 96.0	\$ 85.0	\$ 85.0
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	170.3	1,067.0	159.3	1,292.1
RESL	-	17.5	-	18.4

32. SUBSEQUENT EVENTS

Emera

During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the second instalment of the Debenture Offering of the pending TECO Energy acquisition of \$1.457 billion.

On October 16, 2015, Emera permanently reduced the USD bridge facility in the amount of \$588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing discussed below.

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, assuming payment of the Final Instalment.

NSPI

On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of \$25.00 per share for a total of \$135 million.

Emera Energy

On October 8, 2015, Bear Swamp refinanced its \$125 million USD bank debt that was due to mature in 2017 and issued \$400 million USD in senior secured 10-year bonds, with \$375 million USD at a fixed rate of 4.89 per cent, and \$25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a \$178 million (\$137 million USD) non-taxable distribution.

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through November 13, 2015, the date the financial statements were issued.