EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

March 31, 2016 and 2015

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2016**	 2015
Operating revenues		
Regulated	**$ 586.6**	$ 631.2
Non-regulated	**290.4**	257.3
Total operating revenues	**877.0**	888.5
Operating expenses		
Regulated fuel for generation and purchased power	**197.7**	255.0
Regulated fuel adjustment mechanism and fixed cost deferrals (note 5)	**17.6**	(7.2)
Non-regulated fuel for generation and purchased power	**109.8**	150.4
Non-regulated direct costs	**2.3**	4.4
Operating, maintenance and general	**175.7**	155.1
Provincial, state and municipal taxes	**16.4**	15.9
Depreciation and amortization	**87.5**	82.8
Total operating expenses	**607.0**	656.4
Income from operations	**270.0**	232.1
Income from equity investments (note 6)	**26.0**	25.9
Other income (expenses), net (note 7)	**(139.2)**	21.9
Interest expense, net (note 8)	**75.2**	44.4
Income before provision for income taxes	**81.6**	235.5
Income tax expense (recovery) (note 9)	**26.8**	61.4
Net income	**54.8**	174.1
Non-controlling interest in subsidiaries	**3.5**	6.3
Net income of Emera Incorporated	**51.3**	167.8
Preferred stock dividends	**7.0**	7.7
Net income attributable to common shareholders	**$ 44.3**	$ 160.1
Weighted average shares of common stock outstanding (in millions)		
Basic	**148.7**	144.9
Diluted	**149.3**	148.8
Earnings per common share (note 10)		
Basic	**$ 0.30**	$ 1.10
Diluted	**$ 0.30**	$ 1.09
Dividends per common share declared	**$ 0.4750**	$ 0.3875

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 March 31 **2016**	 2015
Net income	**$ 54.8**	$ 174.1
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**(161.5)**	189.4
Cash flow hedges		
Net derivative gains (losses) (2)	**14.1**	(15.9)
Less: reclassification adjustment for losses (gains) included in income (3)	**0.9**	(1.1)
Net effects of cash flow hedges	**15.0**	(17.0)
Unrealized gains on available-for-sale investment		
Unrealized gain (loss) arising during the period	**0.4**	0.4
Net unrealized holding gains (losses)	**0.4**	0.4
Net change in unrecognized pension and post-retirement benefit obligation (4)	**8.6**	10.6
Other comprehensive income (loss) (5)	**(137.5)**	183.4
Comprehensive income (loss)	**(82.7)**	357.5
Comprehensive income (loss) attributable to non-controlling interest	**(3.3)**	19.5
Comprehensive Income of Emera Incorporated	**$ (79.4)**	$ 338.0

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

1) Net of tax expense of $1.8 million (2015 - $0.1 million tax expense) for the three months ended March 31, 2016.
2) Net of tax expense of $0.1 million (2015 - $0.2 million tax expense) for the three months ended March 31, 2016.
3) Net of tax recovery of $1.6 million (2015 - $2.2 million tax recovery) for the three months ended March 31, 2016.
4) Net of tax expense of nil (2015 - $0.6 million tax expense) for the three months ended March 31, 2016.
5) Net of tax expense of $0.3 million (2015 - $1.3 million tax recovery) for the three months ended March 31, 2016.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars		March 31 **2016**		December 31 2015
Assets				
Current assets				
Cash and cash equivalents	**$**	**999.5**	$	1,073.4
Restricted cash		**22.2**		19.3
Receivables, net (note 12)		**610.3**		577.4
Income taxes receivable		**15.8**		12.1
Inventory (note 13)		**260.8**		314.3
Derivative instruments (notes 14 and 15)		**92.4**		249.5
Regulatory assets (notes 5 and 16)		**78.2**		94.2
Prepaid expenses		**40.4**		18.3
Due from related parties (note 17)		**1.5**		2.3
Other current assets (note 18)		**168.3**		234.8
Total current assets		**2,289.4**		2,595.6
Property, plant and equipment, net of accumulated depreciation of $3,723.0 and $3,732.4, respectively		**6,014.9**		6,188.0
Other assets				
Income taxes receivable		**48.3**		48.7
Deferred income taxes		**47.0**		32.2
Derivative instruments (notes 14 and 15)		**85.4**		167.6
Pension and post-retirement asset (note 19)		**8.6**		8.7
Regulatory assets (notes 5 and 16)		**619.1**		605.3
Net investment in direct financing lease		**478.7**		480.1
Investments subject to significant influence (note 6)		**1,209.7**		1,145.3
Available-for-sale investments (note 20)		**106.2**		116.0
Goodwill		**247.6**		264.1
Intangibles, net of accumulated amortization of $93.8 and $92.8, respectively		**190.9**		191.9
Due from related parties (note 17)		**2.5**		2.5
Other long-term assets		**100.3**		104.0
Total other assets		**3,144.3**		3,166.4
Total assets	**$**	**11,448.6**	$	11,950.0

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

Emera Incorporated
Condensed Consolidated Balance Sheets – (Unaudited) Continued

As at millions of Canadian dollars		**March 31 2016**		December 31 2015
Liabilities and Equity				
Current liabilities				
Short-term debt	**$**	**10.2**	$	15.9
Current portion of long-term debt		**272.6**		274.0
Accounts payable		**371.5**		394.2
Income taxes payable		**8.6**		8.1
Convertible debentures represented by instalment receipts (note 22)		**681.8**		681.5
Derivative instruments (notes 14 and 15)		**147.9**		349.2
Regulatory liabilities (note 16)		**75.0**		98.9
Pension and post-retirement liabilities (note 19)		**7.0**		7.0
Due to related party (note 17)		**2.3**		2.1
Other current liabilities (note 21)		**182.7**		204.3
Total current liabilities		**1,759.6**		2,035.2
Long-term liabilities				
Long-term debt		**3,714.2**		3,734.6
Deferred income taxes		**793.6**		761.7
Derivative instruments (notes 14 and 15)		**79.2**		96.1
Regulatory liabilities (note 16)		**221.2**		271.7
Asset retirement obligations		**115.6**		114.7
Pension and post-retirement liabilities (note 19)		**296.0**		303.4
Other long-term liabilities (note 23)		**272.3**		298.5
Total long-term liabilities		**5,492.1**		5,580.7
Commitments and contingencies (note 24)				
Equity				
Common stock, no par value, unlimited shares authorized, 148.35 million and 147.21 million shares issued and outstanding, respectively (note 25)		**2,199.0**		2,157.5
Cumulative preferred stock, Series A, B, C, E and F, par value $25 per share; unlimited shares authorized, 3.9 million, 2.1 million, 10 million, 5 million, and 8 million shares issued and outstanding, respectively		**709.5**		709.5
Contributed surplus		**35.3**		28.8
Accumulated other comprehensive income (loss) (note 11)		**5.8**		136.5
Retained earnings		**1,142.1**		1,167.8
Total Emera Incorporated equity		**4,091.7**		4,200.1
Non-controlling interest in subsidiaries (note 26)		**105.2**		134.0
Total equity		**4,196.9**		4,334.1
Total liabilities and equity	**$**	**11,448.6**	$	11,950.0

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

Approved on behalf of the Board of Directors

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

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

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Three months ended March 31 2016	 2015
Operating activities		
Net income	**$ 54.8**	$ 174.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**90.7**	85.6
Income from equity investments, net of dividends	**(12.6)**	(12.8)
Allowance for equity funds used during construction	**(0.9)**	(0.3)
Deferred income taxes, net	**8.8**	12.3
Net change in pension and post-retirement liabilities	**6.5**	6.3
Regulated fuel adjustment mechanism and fixed cost deferrals	**17.4**	(8.4)
Net change in fair value of derivative instruments	**(28.6)**	4.7
Net change in regulatory assets and liabilities	**(4.6)**	2.2
Net change in capitalized transportation capacity	**56.3**	15.3
Unrealized foreign exchange loss	**44.7**	-
Other operating activities, net	**(0.1)**	(21.5)
Changes in non-cash working capital:		
Receivables, net	**(53.7)**	(92.7)
Income taxes receivable	**(6.7)**	(13.5)
Inventory	**47.9**	20.5
Prepaid expenses	**(23.3)**	(28.0)
Due from related party	**0.3**	(0.9)
Other current assets	**0.2**	(0.5)
Accounts payable	**(2.3)**	(6.7)
Income taxes payable	**4.1**	1.3
Other current liabilities	**(18.3)**	(17.4)
Net cash provided by operating activities	**180.6**	119.6
Investing activities		
Additions to property, plant and equipment	**(77.2)**	(81.0)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(53.1)**	-
Additions to intangible assets	**(8.3)**	(1.5)
Proceeds on sale of investment subject to significant influence	**-**	282.3
Other investing activities	**(0.7)**	(3.9)
Net cash (used in) provided by investing activities	**(139.3)**	195.9
Financing activities		
Change in short-term debt, net	**(7.2)**	(271.9)
Retirement of long-term debt	**(4.0)**	(6.5)
Proceeds from long-term debt	**-**	250.0
Net borrowings (repayments) under committed credit facilities	**20.7**	(168.4)
Issuance of common stock, net of issuance costs (note 25)	**14.6**	2.5
Dividends on common stock	**(47.0)**	(40.1)
Dividends on preferred stock	**(7.0)**	(7.7)
Dividends paid by subsidiaries to non-controlling interest	**(1.8)**	(3.9)
Other financing activities	**(14.1)**	(13.3)
Net cash used in financing activities	**(45.8)**	(259.3)
Effect of exchange rate changes on cash and cash equivalents	**(69.4)**	28.0
Net (decrease) increase in cash and cash equivalents	**(73.9)**	84.2
Cash and cash equivalents, beginning of period	**1,073.4**	221.1
Cash and cash equivalents, end of period	**$ 999.5**	**$** 305.3
Cash and cash equivalents consists of:		
Cash	**$ 260.2**	**$** 235.5
Short-term investments	**739.3**	69.8
Cash and cash equivalents	**$ 999.5**	**$** 305.3
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 23.0**	$ 15.6

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

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

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income ("AOCI")	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
For the three months ended March 31, 2016								
Balance, December 31, 2015	$ 2,157.5	$ 709.5	$ 28.8	$ 136.5	$ 1,167.8	$ 4,200.1	$ 134.0	$ 4,334.1
Net income of Emera Incorporated	-	-	-	-	51.3	51.3	3.5	54.8
Other comprehensive income (loss), net of tax expense of $0.3 million	-	-	-	(130.7)	-	(130.7)	(6.8)	(137.5)
Dividends declared on preferred stock (Series A: $0.1597/share, Series B: $0.1425/share, Series C: $ 0.25625/share, Series E: $0.28125/share and Series F: $0.265625/share)	-	-	-	-	(7.0)	(7.0)	-	(7.0)
Dividends declared on common stock ($0.4750/share)	-	-	-	-	(70.0)	(70.0)	-	(70.0)
Common stock issued under purchase plan	25.0	-	-	-	-	25.0	-	25.0
Senior management stock options exercised	13.6	-	(1.0)	-	-	12.6	-	12.6
Stock option expense		-	0.4	-	-	0.4	-	0.4
Employee Share Purchase Plan	0.2	-	-	-	-	0.2	-	0.2
Preferred dividends paid and payable by subsidiaries to non-controlling interest	-	-	-	-	-	-	(1.8)	(1.8)
Acquisition of non-controlling interest of ECI	2.7	-	7.1	-	-	9.8	(23.7)	(13.9)
Balance, March 31, 2016	$ 2,199.0	$ 709.5	$ 35.3	$ 5.8	$ 1,142.1	$ 4,091.7	$ 105.2	$ 4,196.9

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

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

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income ("AOCI")	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
For the three months ended March 31, 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	-	-	-	-	167.8	167.8	6.3	174.1
Other comprehensive income (loss), net of tax recovery of $1.3 million	-	-	-	170.2	-	170.2	13.2	183.4
Dividends declared on preferred stock (Series A: $0.275/share, Series C: $ 0.25625/share, Series E: $0.28125/share and Series F: $0.265625/share)	-	-	-	-	(7.7)	(7.7)	-	(7.7)
Dividends declared on common stock ($0.3875/share)	-	-	-	-	(55.7)	(55.7)	-	(55.7)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(0.7)	(0.7)
Common stock issued under purchase plan	17.4	-	-	-	-	17.4	-	17.4
Senior management stock options exercised	0.6	-	-	-	-	0.6	-	0.6
Stock option expense	-	-	0.3	-	-	0.3	-	0.3
Other stock-based compensation	0.2	-	-	-	-	0.2	-	0.2
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(3.5)	(3.5)
Other	-	-	-	-	-	-	(0.1)	(0.1)
Balance, March 31, 2015	$ 2,034.6	$ 709.5	$ 9.1	$ (177.4)	$ 1,116.1	$ 3,691.9	$ 321.8	$ 4,013.7

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

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 March 31, 2016 included the following:

- Nova Scotia Power Inc. ("NSPI"), which is a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving 507,000 customers;
- Emera Maine provides electric transmission and distribution services to 158,000 customers in the State of Maine in the United States;
- a 100.0 per cent interest (December 31, 2015 – 95.5 per cent) 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 51.9 per cent interest (December 31, 2015 – 49.6 per cent indirect interest) through ECI in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica, serving 36,000 customers; and a 19.1 per cent indirect interest (December 31, 2015 – 18.2 per cent indirect interest) through ECI in St. Lucia Electricity Services Limited ("Lucelec"), which is a vertically integrated regulated electric utility in St. Lucia;
- a 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), which is a vertically integrated utility and sole provider of electricity on Grand Bahama Island, serving 19,000 customers;
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), which is a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy Canada ("REC"), which expires in 2034;
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), focused on two transmission investments related to the development of an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, scheduled to be 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;
  - 59.0 per cent investment (December 31, 2015 – 55.1 per cent) in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017.

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

Emera Incorporated and its subsidiaries also own investments in other energy-related 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;
- 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;
- a 19.4 per cent (December 31, 2015 – 19.6 per cent) investment in Algonquin Power & Utilities Corp. ("APUC"), which is a public company traded on the Toronto Stock Exchange under the symbol "AQN";
- and other investments.

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 ("the Transaction"). 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, and includes the assumption of approximately $3.9 billion USD of debt.

The closing of the acquisition, expected to occur mid-2016, is subject to approval by the New Mexico Public Regulation Commission ("NMPRC"), and the satisfaction of customary closing conditions. On April 11, 2016, Emera and TECO Energy filed an unopposed Stipulation Agreement reflecting a settlement reached with intervening parties in the acquisition case pending before the NMPRC for approval of Emera's proposed acquisition of TECO Energy and the indirect acquisition of the New Mexico Gas Co. The hearing for Emera's pending acquisition of TECO Energy occurred on May 2, 2016. A decision is expected mid-2016.

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 nearly 725,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves nearly 365,000 customers across Florida; and New Mexico Gas Co., also a regulated gas distribution utility which serves more than 515,000 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"). They 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, 2015.

In the opinion of management, these unaudited condensed consolidated interim financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera Incorporated. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2016.

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

C. Use of Management Estimates

The preparation of consolidated financial statements in accordance with United States generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, capitalized overhead, depreciation, 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

The new US GAAP accounting policies that are applicable to, and were adopted by Emera, effective during 2016, are described as follows:

Income Statement – Extraordinary and Unusual Items, Accounting Standard Update ("ASU") 2015-01

In January 2015, the Financial Accounting Standards Board ("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. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Consolidation, ASU 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. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the variable interest entity ("VIE") characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. All legal entities are subject to re-evaluation under the revised consolidation model. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Interest – Imputation of Interest, 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 on 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. The Company has adopted this standard effective Q1 2016 and December 31, 2015 balances have been retrospectively restated. This change resulted in $62.3 million of deferred financing costs, as at December 31, 2015, previously presented as other assets, being reclassified as a deduction from the carrying amount of the related long-term debt and convertible debentures represented by instalment receipts on the Consolidated Balance Sheets.

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

Compensation – Retirement Benefits, ASU 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. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU 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, the customer would account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer would account for the arrangement as a service contract. The guidance does not change GAAP for a customer's accounting for service contracts. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Technical Corrections and Improvements, ASU 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. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Inventory – Simplifying the Measurement of Inventory, ASU 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 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, ASU 2016-05
In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships*. The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship provided that all other hedge accounting criteria continue to be met. ASU 2016-05 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and early adoption is permitted. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

Investments – Equity Method and Joint Ventures, ASU 2016-07
In March 2016, the FASB issued ASU 2016-07, *Investments – Equity Method and Joint Ventures*, which is part of FASB's initiative to reduce complexity in accounting standards. This standard eliminates the requirements of an investor to retroactively account for an investment under the equity method when an investment qualifies for equity method accounting. ASU 2016-07 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016, with early adoption permitted. The Company has adopted this standard in Q1 2016, with no impact on its consolidated financial statements.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers, ASU 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. In March 2016, the FASB issued ASU 2016-08, *Revenue from Contracts with Customers: Principal versus Agent Considerations*. The amendments are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU 2016-10 *Revenue from Contracts with Customers: Identifying Performance Obligations and Licensing*. The guidance will be effective beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The Company is continuing to evaluate the impact of adoption of these standards on its consolidated financial statements.

Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities, ASU 2016-01
In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. ASU 2016-01 is 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.

Leases (Topic 842), ASU 2016-02
In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for lease terms of more than 12 months. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. ASU 2016-02 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and will be applied using a modified retrospective approach. 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 March 31, 2016, Emera has six reportable segments, specifically:

- NSPI;
- Emera Maine;
- Emera Caribbean (ECI and its subsidiaries including BLPC, Domlec, GBPC, 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 and an equity investment in Bear Swamp; and
- Corporate and Other (Emera Utility Services, ENL, Corporate, other strategic investments (including APUC) and holding companies.

millions of Canadian dollars	NSPI	Emera Maine	Emera Caribbean	Pipelines	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the three months ended March 31, 2016								
Operating revenues from external customers (1)	$ 397.5	$ 79.6	$ 97.6	$ 12.9	$ 287.7	$ 2.0	$ (0.6)	$ 876.7
Inter-segment revenues (1)	-	-	-	-	3.3	6.4	(9.4)	0.3
Total operating revenues	397.5	79.6	97.6	12.9	291.0	8.4	(10.0)	877.0
Net income attributable to common shareholders	52.5	9.3	9.8	9.4	93.4	(130.1)	-	44.3
For the three months ended March 31, 2015								
Operating revenues from external customers (1)	$ 446.5	$ 69.2	$ 103.0	$ 13.1	$ 254.2	$ 3.2	$ (0.5)	$ 888.7
Inter-segment revenues (1)	-	-	2.4	-	3.6	5.6	(11.8)	(0.2)
Total operating revenues	446.5	69.2	105.4	13.1	257.8	8.8	(12.3)	888.5
Net income attributable to common shareholders	68.0	11.5	8.8	9.9	64.9	(3.0)	-	160.1

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

5. REGULATED FUEL ADJUSTMENT MECHANISM AND FIXED COST DEFERRALS

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

For the millions of Canadian dollars	Three months ended March 31 **2016**	 2015
Regulated fuel adjustment mechanism (see chart below)	**$ 13.8**	$ (5.4)
Application of non-fuel revenue	**3.8**	7.0
Regulated fixed cost deferral related to 2015 demand side management	**-**	(8.8)
	$ 17.6	$ (7.2)

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 FAM is subject to an incentive, with NSPI retaining or absorbing 10 per cent of the over or under-recovered amount to a maximum of $5 million. The incentive was suspended for 2012 to 2015, as a result of UARB approved settlement agreements and is in effect for 2016.

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

For the millions of Canadian dollars	Three months ended March 31 **2016**	2015
Over (Under) recovery of current period Fuel Costs	**$ 10.0**	$ (23.6)
Recovery from (rebate to) customers of prior years' Fuel Costs	**3.8**	18.2
Regulated fuel adjustment mechanism	**$ 13.8**	$ (5.4)

The deferred FAM amounts are recognized as a "Regulatory asset" or "Regulatory liability" on the Consolidated Balance Sheets. The FAM regulatory asset balance of $8.5 million and the FAM regulatory liability balance of $55.1 million is disclosed in Note 16 and includes associated interest recorded as "Interest expense, net" on the Consolidated Statements of Income.

In December 2015, the UARB approved NSPI's 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's filings. Approved customer rates reset the base cost of fuel rate for 2016 and seek to recover a total of $13.7 million of prior years' unrecovered Fuel Costs in 2016. Recovery of these costs began January 1, 2016.

On December 18, 2015, the Electricity Plan Implementation (2015) Act (the "Electricity Plan Act") was enacted by the Province of Nova Scotia. In accordance with the Electricity Plan Act, NSPI filed with the UARB, on March 7, 2016, a three-year rate plan for Fuel Costs, requesting an average increase of 1.3 per cent for 2017 through 2019. A hearing is scheduled for June 13, 2016. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates during this period will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers subsequent to 2019.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. The audit for fiscal 2014 and 2015 is currently underway.

<u>Application of Non-Fuel Revenues</u>

The Electricity Plan Act further directed NSPI to apply any non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved to be applied to the FAM to be used in the 2017 to 2019 period. The exception to this direction is application of a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. This amount totals $4.6 million. As a result, as at December 31, 2015, NSPI has deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

In Q1 2016, NSPI applied $3.8 million of non-fuel revenues to the FAM for periods 2017 to 2019. This was a result of applying the tax benefits associated with the South Canoe and Sable Wind Projects as directed by the Electricity Plan Act.

Fixed Cost Deferral Related to 2015 DSM

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from electricity bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs were set for 2015 at $35 million and were 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. The Electricity Plan Act placed a cap of $34.0 million on 2019 DSM spending. The 2016 DSM cost of $24.7 million will not be deferred and will be charged to earnings.

The deferred DSM amounts from 2015 are recognized as a "Regulatory asset" on the Consolidated Balance Sheets. The DSM regulatory asset balance of $35.6 million is disclosed in Note 16 and includes associated interest that is recorded as "Interest expense, net" on the Consolidated Statements of Income.

For the millions of Canadian dollars		**2016**
DSM regulatory asset – Balance as at January 1	**$**	**36.4**
Recovery of regulatory asset recorded as regulatory amortization		**(1.5)**
Interest on DSM balance		**0.7**
DSM regulatory asset – Balance as at March 31	**$**	**35.6**

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value as at		Equity Income For the three months ended		Percentage of
	March 31	December 31		March 31	Ownership
millions of Canadian dollars	**2016**	2015	**2016**	2015	**2016**
APUC (1) (2)	**$ 520.1**	$ 503.7	**$ 9.0**	$ 6.6	19.4
LIL (3)	**251.1**	208.1	**4.7**	1.7	59.0
NSPML	**206.4**	187.6	**4.4**	3.6	100.0
M&NP	**178.2**	188.7	**5.9**	5.9	12.9
Lucelec	**36.8**	39.4	**0.6**	0.6	19.1
Maine Electric Power Company Inc.	**6.6**	7.0	**-**	0.1	21.7
Cape Sharp Tidal Venture Ltd.	**5.2**	5.1	**-**	-	20.0
Chester Static Var Compensator	**4.9**	5.3	**-**	-	50.0
Maine Yankee Atomic Power Company	**0.4**	0.4	**-**	-	12.0
Bear Swamp (4)	**-**	-	**1.4**	3.1	50.0
Northeast Wind Partnership II, LLC (“NWP”)	**-**	-	**-**	4.3	-
	$ 1,209.7	$ 1,145.3	**$ 26.0**	$ 25.9	

(1) As at March 31, 2016, the market price per share was $10.87 (December 31, 2015 - $10.91), which indicates a fair market value of this investment of $685.4 million (December 31, 2015 – $684.5 million). Emera holds 50.1 million shares and 12.9 million outstanding subscription receipts and dividend equivalents as at March 31, 2016 at an average book value of $8.25 per share. Carrying value reflects a cash cost of $371.2 million, plus non-cash gains recognized on conversion of prior subscriptions receipts into common shares, dilution gains or losses, and equity income or loss, less dividends received. The outstanding subscription receipts, with an average conversion price of $9.19 will automatically convert to common shares in Q4 2016 if an election is not made. If converted, Emera’s interest would increase to 23.2 per cent.
(2) Emera's Strategic Investment Agreement with APUC and a ruling by the Maine Public Utilities ("MPUC") limits Emera's 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 March 31, 2016, Emera is in compliance with both of these requirements.
(3) 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 59.0 per cent.
(4) Bear Swamp's credit investment balance is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.

Equity investments include a $138.1 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.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 27). NSPML's consolidated summarized balance sheet is illustrated as follows:

As at millions of Canadian dollars	**March 31 2016**	December 31 2015
Balance Sheet		
Current assets	**$ 501.2**	$ 438.7
Property, plant and equipment	**750.7**	647.7
Non-current assets	**466.0**	565.6
Total assets	**$ 1,717.9**	$ 1,652.0
Current liabilities	**$ 173.0**	$ 129.8
Non-current liabilities	**1,338.5**	1,334.6
Equity	**206.4**	187.6
Total liabilities and equity	**$ 1,717.9**	$ 1,652.0

7. OTHER INCOME (EXPENSES), NET

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

For the millions of Canadian dollars	Three months ended March 31 **2016**	2015
Allowance for equity funds used during construction	**$ 0.9**	**$** 0.3
Investment income	**0.5**	0.3
Foreign exchange gains (losses)	**(1.5)**	1.9
Amortization of defeasance costs	**(1.7)**	(1.7)
Foreign exchange gains (losses) and mark-to-market adjustments related to the pending TECO Energy acquisition	**(139.5)**	-
Gain on sale of NWP investment	**-**	18.6
Other	**2.1**	2.5
	$ (139.2)	$ 21.9

8. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Three months ended March 31 **2016**	2015
Interest on debt	**$ 48.7**	$ 47.3
Interest on convertible debentures represented by instalment receipts (1)	**21.9**	-
Allowance for borrowed funds used during construction	**(0.7)**	(2.2)
Interest revenue	**(0.9)**	(2.1)
Other	**6.2**	1.4
	$ 75.2	$ 44.4

(1) In 2015, Emera completed the sale of $2.1 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts ("Debentures" or "the Debenture Offering" or "Convertible Debentures").

9. INCOME TAXES

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

For the millions of Canadian dollars	Three months ended March 31 **2016**	**2015**
Income before provision for income taxes	**$ 81.6**	**$ 235.5**
Statutory income tax rate	**31.0%**	**31.0%**
Income taxes, at statutory income tax rate	**25.3**	**73.0**
Non-deductible portion of mark-to-market losses related to pending TECO Energy acquisition	**21.6**	**-**
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(13.1)**	**(9.4)**
Tax effect of equity earnings	**(2.9)**	**(2.3)**
Tax effect of foreign exchange	**(2.3)**	**2.9**
Other	**(1.8)**	**(2.8)**
Income tax expense (recovery)	**$ 26.8**	**$ 61.4**
Effective income tax rate	**32.8%**	**26.1%**

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

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

For the millions of Canadian dollars		Three months ended March 31
	2016	2015
Income tax expense (recovery) – current	**$ 18.0**	$ 49.1
Income tax expense (recovery) – deferred	**8.8**	12.3
Income tax expense (recovery)	**$ 26.8**	$ 61.4

NSPI and the Canada Revenue Agency ("CRA") are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62.3 million, including 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. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years.

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

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

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 March 31 **2016**	2015
Numerator		
Net income attributable to common shareholders	**$ 44.3**	$ 160.1
Preferred stock dividends of subsidiary	**-**	2.0
Diluted numerator	**44.3**	162.1
Denominator		
Weighted average shares of common stock outstanding	**147.7**	144.0
Weighted average deferred share units outstanding	**1.0**	0.9
Weighted average shares of common stock outstanding – basic	**148.7**	144.9
Effect of dilutive securities	**-**	3.3
Stock-based compensation	**0.6**	0.6
Weighted average shares of common stock outstanding – diluted	**149.3**	148.8
Earnings per common share		
Basic	**$ 0.30**	$ 1.10
Diluted	**$ 0.30**	$ 1.09

Effect on EPS of Convertible Debentures

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 installment has been made, each Debenture will be convertible into common shares of Emera. This conversion can occur at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The conversion price is $41.85 per common share, and the conversion rate is 23.8949 common shares per $1,000 principal amount of Debentures (note 22). Accordingly, a total of approximately 52.2 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 AOCI
For the three months ended March 31, 2016					
Balance, January 1, 2016	$ (35.1)	$ (317.6)	$ 0.3	$ 488.9	$ 136.5
Other comprehensive income (loss) before reclassifications	14.1	-	0.4	(154.7)	(140.2)
Amounts reclassified from accumulated other comprehensive income loss (gain)	0.9	8.6	-	-	9.5
Net current period other comprehensive income (loss)	15.0	8.6	0.4	(154.7)	(130.7)
Balance, March 31, 2016	$ (20.1)	$ (309.0)	$ 0.7	$ 334.2	$ 5.8

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 AOCI
For the three months ended March 31, 2015					
Balance, January 1, 2015	$ (7.9)	$ (424.7)	$ 2.6	$ 82.4	$ (347.6)
Other comprehensive income (loss) before reclassifications	(15.9)	-	0.4	176.2	160.7
Amounts reclassified from accumulated other comprehensive income loss (gain)	(1.1)	10.6	-	-	9.5
Net current period other comprehensive income (loss)	(17.0)	10.6	0.4	176.2	170.2
Balance, March 31, 2015	$ (24.9)	$ (414.1)	$ 3.0	$ 258.6	$ (177.4)

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

For the		Three months ended March 31	
millions of Canadian dollars		**2016**	2015
	Affected line item in the Consolidated Statements of Income	Amounts reclassified from AOCI	
Losses (gain) on derivatives recognized as cash flow hedges			
Power and gas swaps	Non-regulated fuel for generation and purchased power	**$ (4.2)**	$ (5.6)
Interest rate swaps	Income from equity investments	**0.3**	0.2
Foreign exchange forwards	Operating revenue - regulated	**3.2**	2.1
Total before tax		**(0.7)**	(3.3)
	Income tax expense (recovery)	**1.6**	2.2
Total net of tax		**$ 0.9**	$ (1.1)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	OM&G	**$ 10.9**	$ 11.9
Past service costs (gains)	OM&G	**(2.3)**	(0.7)
Total before tax		**8.6**	11.2
	Income tax expense (recovery)	**-**	(0.6)
Total net of tax		**$ 8.6**	$ 10.6
Net change in available-for-sale investments			
Total reclassifications out of AOCI, net of tax, for the period		**$ 9.5**	$ 9.5

12. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars	**March 31 2016**	December 31 2015
Customer accounts receivable – billed	**$ 437.8**	$ 406.3
Customer accounts receivable – unbilled	**146.6**	144.2
Total customer accounts receivable	**584.4**	550.5
Allowance for doubtful accounts	**(12.1)**	(12.6)
Customer accounts receivable, net	**572.3**	537.9
Other	**38.0**	39.5
	$ 610.3	$ 577.4

13. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars	**March 31 2016**	December 31 2015
Fuel	**$ 141.1**	$ 185.3
Materials	**98.8**	100.4
Emission credits (1)	**20.9**	28.6
	$ 260.8	$ 314.3

(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 (notes 21 and 23) associated with these programs.

14. DERIVATIVE INSTRUMENTS

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

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

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

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

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

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

3. Derivatives entered into by 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:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**March 31 2016**	December 31 2015	**March 31 2016**	December 31 2015
Current				
Cash flow hedges				
Power swaps	**$ 5.3**	$ 7.9	**$ 0.5**	$ 0.5
Foreign exchange forwards	**0.3**	-	**10.2**	14.4
	5.6	7.9	**10.7**	14.9
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	-	**7.7**	11.7
Natural gas purchases and sales	**0.7**	1.5	**2.3**	0.7
Heavy fuel oil purchases	**-**	-	**16.4**	20.5
Foreign exchange forwards	**56.2**	85.3	**7.6**	10.5
Physical natural gas purchases and sales	**0.8**	1.8	**-**	-
	57.7	88.6	**34.0**	43.4
HFT derivatives				
Power swaps and physical contracts	**21.1**	150.8	**23.7**	118.5
Foreign exchange options	**0.3**	98.6	**1.0**	2.1
Natural gas swaps, futures, forwards, physical contracts	**64.0**	-	**132.1**	358.8
	85.4	249.4	**156.8**	479.4
Other derivatives				
Foreign exchange forwards	**1.1**	92.1	**3.8**	-
	1.1	92.1	**3.8**	-
Total gross current derivatives	**149.8**	438.0	**205.3**	537.7
Impact of master netting agreements with intent to settle net or simultaneously	**(57.4)**	(188.5)	**(57.4)**	(188.5)
Total current derivatives	**92.4**	249.5	**147.9**	349.2
Long-term				
Cash flow hedges				
Power swaps	**5.7**	11.6	**3.7**	4.1
Foreign exchange forwards	**0.4**	0.3	**14.1**	27.2
	6.1	11.9	**17.8**	31.3
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**3.0**	-	**4.0**	4.4
Heavy fuel oil purchases	**-**	-	**13.3**	16.6
Foreign exchange forwards	**72.0**	121.4	**-**	-
	75.0	121.4	**17.3**	21.0
HFT derivatives				
Power swaps and physical contracts	**14.1**	12.9	**27.5**	28.2
Natural gas swaps, futures, forwards and physical contracts	**24.2**	72.3	**47.4**	62.6
Foreign exchange options	**0.7**	0.4	**0.7**	1.4
	39.0	85.6	**75.6**	92.2
Other derivatives				
Interest rate swap	**-**	-	**3.2**	2.9
	-	-	**3.2**	2.9
Total gross long-term derivatives	**120.1**	218.9	**113.9**	147.4
Impact of master netting agreements with intent to settle net or simultaneously	**(34.7)**	(51.3)	**(34.7)**	(51.3)
Total long-term derivatives	**85.4**	167.6	**79.2**	96.1
Total derivatives	**$ 177.8**	$ 417.1	**$ 227.1**	$ 445.3

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

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**March 31 2016**	December 31 2015	**March 31 2016**	December 31 2015
Regulatory deferral	**$ 1.4**	$ 0.1	**$ 1.4**	$ 0.1
HFT derivatives	**90.7**	239.7	**90.7**	239.7
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 92.1**	$ 239.8	**$ 92.1**	$ 239.8

Cash Flow Hedges

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

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

For the millions of Canadian dollars			**2016**	Three months ended March 31		2015
	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	**$ (1.0)**	**$ -**	**$ -**	$ (0.6)	$ -	$ -
Realized gain (loss) in Non-regulated fuel for generation and purchased power	**4.2**	**-**	**-**	5.6	-	-
Realized gain (loss) in Operating revenue – Regulated	**-**	**-**	**(3.2)**	-	-	(2.1)
Realized gain (loss) in Income from equity investments	**-**	**(0.3)**	**-**	-	(0.2)	-
Total gains (losses) in Net income	**$ 3.2**	**$ (0.3)**	**$ (3.2)**	$ 5.0	$ (0.2)	$ (2.1)

As at millions of Canadian dollars			**March 31 2016**			December 31 2015
	Power Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ 0.9**	**$ (0.9)**	**$ (23.6)**	$ 3.5	$ (1.1)	$ (41.7)

The Company expects $8.7 million of unrealized losses currently in AOCI to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at March 31, 2016, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	**2016**	2017	2018	2019	2020
Power swaps (megawatt hours ("MWh")) purchases	**0.2**	0.3	-	-	-
Foreign exchange forwards (USD) sales	**40.4**	53.4	44.8	30.0	30.0
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 March 31, 2016		
	Commodity swaps and forwards	**Physical natural gas purchases and sales**	**Foreign exchange forwards**
Unrealized gain (loss) in regulatory assets	$ 4.1	$ -	$ 2.9
Unrealized gain (loss) in regulatory liabilities	0.9	(1.0)	(50.4)
Realized (gain) loss in regulatory assets	1.7	-	-
Realized (gain) loss in inventory (1)	-	-	(19.4)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	5.7	-	(8.7)
Total change in derivative instruments	**$ 12.4**	**$ (1.0)**	**$ (75.6)**

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

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

For the millions of Canadian dollars	Three months ended March 31, 2015		
	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	$ (8.3)	$ -	$ (2.7)
Unrealized gain (loss) in regulatory liabilities	(0.1)	4.7	92.6
Realized (gain) loss in regulatory assets	3.4	-	-
Realized (gain) loss in inventory (1)	(0.7)	-	(12.7)
Realized (gain) loss in property, plant and equipment	-	-	(1.0)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	4.0	(0.1)	(2.8)
Total change in derivative instruments	$ (1.7)	$ 4.6	$ 73.4

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

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

Commodity Swaps and Forwards

As at March 31, 2016, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2016	2017-2019
millions	**Purchases**	Purchases
Coal (metric tonnes)	**0.2**	2.3
Natural Gas (mmbtu)	**3.2**	-
Heavy fuel oil (bbls)	**0.5**	0.5

Foreign Exchange Swaps and Forwards

As at March 31, 2016, the Company had the following notional volumes of foreign exchange swaps and forward contracts related to commodity contracts that are expected to settle as outlined below:

	2016	2017-2019
Fuel purchases exposure (millions of US dollars)	$ 150.8	$ 461.8
Weighted average rate	1.0331	1.0932
% of USD requirements	96%	90%

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	Three months ended March 31	
millions of Canadian dollars	**2016**	2015
Power swaps and physical contracts in non-regulated operating revenues	**$ (5.5)**	$ 1.5
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**227.9**	92.5
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**0.9**	(1.8)
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(1.6)**	2.0
Foreign exchange options in non-regulated operating revenue	**(0.8)**	-
	$ 220.9	$ 94.2

As at March 31, 2016, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	**2016**	2017	2018	2019	2020
Natural gas purchases (Mmbtu)	**194.5**	60.6	49.9	43.9	43.9
Natural gas sales (Mmbtu)	**155.8**	33.8	6.1	5.8	5.1
Power purchases (MWh)	**0.6**	0.6	0.6	0.6	0.6
Power sales (MWh)	**1.7**	0.3	0.3	0.3	0.3
Foreign exchange options (USD)	**$ 14.9**	$ 12.5	$ 4.1	-	-
Foreign exchange forwards (EURO) purchases	**-**	0.2	-	-	-

Other Derivatives

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

For the millions of Canadian dollars	**2016** **Interest rate swaps**	**Foreign exchange forwards**	Three months ended March 31 Interest rate swaps	2015 Foreign exchange forwards
Unrealized gain (loss) in other income (expense)	**$**	**$ (94.8)**	$ -	$ -
Unrealized gain (loss) in interest expense, net	**(0.3)**	**-**	-	-
Total gains (losses) in net income	**$ (0.3)**	**$ (94.8)**	$ **-**	$ **-**

As at March 31, 2016, the Company had interest rate swaps in place for the $250 million non-revolving term credit facility in Brunswick Pipeline for interest payments until the debt matures in 2019.

As at March 31, 2016, the Company had a foreign exchange forwards in place for $1,121.7 million USD in 2016 to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition.

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 March 31, 2016, the Company had $86.3 million (December 31, 2015 - $83.2 million) in financial assets, considered to be past due, which have been outstanding for an average 78 days. The fair value of these financial assets is $75.1 million (December 31, 2015 - $71.5 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	**March 31 2016**	December 31 2015
Cash collateral provided to others	**$ 124.9**	$ 106.9
Cash collateral received from others	**1.4**	28.5

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 March 31, 2016, the total fair value of these derivatives, in a liability position, was $227.1 million (December 31, 2015 – $445.3 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.

15. 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 14), 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				**March 31, 2016**
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power swaps	**$ 11.0**	**$ 0.2**	**$ -**	**$ 11.2**
Foreign exchange forwards	**-**	**0.5**	**-**	**0.5**
	11.0	**0.7**	**-**	**11.7**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**1.7**	**-**	**1.7**
Natural gas purchases and sales	**-**	**0.6**	**-**	**0.6**
Foreign exchange forwards	**-**	**128.2**	**-**	**128.2**
Physical natural gas purchases and sales	**-**	**-**	**0.8**	**0.8**
	-	**130.5**	**0.8**	**131.3**
HFT derivatives				
Power swaps and physical contracts	**(3.7)**	**0.4**	**4.8**	**1.5**
Foreign exchange options	**-**	**1.0**	**-**	**1.0**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**2.0**	**8.7**	**20.5**	**31.2**
	(1.7)	**10.1**	**25.3**	**33.7**
Other derivatives				
Foreign exchange forwards	**-**	**1.1**	**-**	**1.1**
	-	**1.1**	**-**	**1.1**
Total assets	**9.3**	**142.4**	**26.1**	**177.8**
Liabilities				
Cash flow hedges				
Power swaps	**4.2**	**-**	**-**	**4.2**
Foreign exchange forwards	**-**	**24.3**	**-**	**24.3**
	4.2	**24.3**	**-**	**28.5**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**10.4**	**-**	**10.4**
Heavy fuel oil purchases	**-**	**29.6**	**-**	**29.6**
Natural gas purchases and sales	**2.1**	**0.1**	**-**	**2.2**
Foreign exchange forwards		**7.6**	**-**	**7.6**
	2.1	**47.7**	**-**	**49.8**
HFT derivatives				
Power swaps and physical contracts	**12.2**	**0.9**	**4.6**	**17.7**
Foreign exchange options	**-**	**1.7**	**-**	**1.7**
Natural gas swaps, futures, forwards and physical contracts	**6.9**	**19.5**	**96.0**	**122.4**
	19.1	**22.1**	**100.6**	**141.8**
Other derivatives				
Foreign exchange forwards	**-**	**3.8**	**-**	**3.8**
Interest rate swap	**-**	**3.2**	**-**	**3.2**
	-	**7.0**	**-**	**7.0**
Total liabilities	**25.4**	**101.1**	**100.6**	**227.1**
Net assets (liabilities)	**$ (16.1)**	**$ 41.3**	**$ (74.5)**	**$ (49.3)**

As at				December 31, 2015
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 19.5	$ -	$ -	$ 19.5
Foreign exchange forwards	-	0.3	-	0.3
	19.5	0.3	-	19.8
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	1.4	-	1.4
Foreign exchange forwards	-	206.7	-	206.7
Physical natural gas purchases and sales	-	-	1.8	1.8
	-	208.1	1.8	209.9
HFT derivatives				
Power swaps and physical contracts	38.3	-	(7.8)	30.5
Foreign exchange forwards	-	0.4	-	0.4
Natural gas swaps, futures, forwards and physical contracts	(0.3)	7.9	56.8	64.4
	38.0	8.3	49.0	95.3
Other derivatives				
Foreign exchange forwards	-	92.1	-	92.1
	-	92.1	-	92.1
Total assets	57.5	308.8	50.8	417.1
Liabilities				
Cash flow hedges				
Power swaps	$ 4.6	$ -	$ -	$ 4.6
Foreign exchange forwards	-	41.6	-	41.6
	4.6	41.6	-	46.2
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	16.1	-	16.1
Natural gas purchases and sales	0.6	-	-	0.6
Heavy fuel oil purchases	-	37.1	-	37.1
Foreign exchange forwards	-	10.5	-	10.5
	0.6	63.7	-	64.3
HFT derivatives				
Power swaps and physical contracts	15.2	-	(2.0)	13.2
Foreign exchange options	-	3.5	-	3.5
Natural gas swaps, futures, forwards and physical contracts	14.4	22.0	278.8	315.2
	29.6	25.5	276.8	331.9
Other derivatives				
Interest rate swaps	-	2.9	-	2.9
	-	2.9	-	2.9
Total liabilities	34.8	133.7	276.8	445.3
Net assets (liabilities)	$ 22.7	$ 175.1	$ (226.0)	$ (28.2)

The Company evaluates the observable inputs of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the three months ended March 31, 2016, there were no transfers between levels.

The change in the fair value of the Level 3 financial assets for the three months ended March 31, 2016 was as follows:

	Regulatory Deferral	*Cash Flow Hedges and HFT Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power Swaps	Natural gas	Total
Balance, January 1, 2016	**$ 1.8**	**$ (7.8)**	**$ 56.8**	**$ 50.8**
Unrealized gains (losses) included in regulatory assets or liabilities	**(1.0)**	**-**	**-**	**(1.0)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**12.6**	**(36.3)**	**(23.7)**
Balance, March 31, 2016	**$ 0.8**	**$ 4.8**	**$ 20.5**	**$ 26.1**

The change in the fair value of the Level 3 financial liabilities for the three months ended March 31, 2016 was as follows:

	Regulatory Deferral	*Cash Flow Hedges and HFT Derivatives*		
millions of Canadian dollars	Heavy fuel oil purchases	Power	Natural gas	Total
Balance, January 1, 2016	**$ -**	**$ (2.0)**	**$ 278.8**	**$ 276.8**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**6.6**	**(182.8)**	**(176.2)**
Balance, March 31, 2016	**$ -**	**$ 4.6**	**$ 96.0**	**$ 100.6**

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					March 31, 2016
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
Regulatory deferral – Physical natural gas purchases and sales	$ 0.8	Modelled pricing	Third-party pricing	$4.09 - $4.70	$4.36
			Probability of default	0.07%	0.01%
HFT derivatives – Power swaps and physical contracts	4.4	Modelled pricing	Third-party pricing	$18.85 - $74.05	$30.20
			Probability of default	0.00% - 0.02%	0.00%
			Discount rate	0.02% - 0.05%	0.03%
	0.4	Modelled pricing	Third-party pricing	$21.51 - $78.42	$35.74
			Correlation factor	0.99% - 0.99%	0.99%
			Probability of default	0.00% - 0.01%	0.01%
			Discount rate	0.02% - 0.11%	0.06%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation	11.7	Modelled pricing	Third-party pricing	$1.35 - $7.76	$2.63
			Probability of default	0.00% - 0.03%	0.01%
			Discount rate	0.00% - 0.27%	0.05%
	8.8	Modelled pricing	Third-party pricing	$1.07 - $7.71	$2.66
			Basis adjustment	-0.12% - 0.74%	0.46%
			Probability of default	0.00% - 0.01%	0.00%
			Discount rate	0.00% - 0.07%	0.00%
Total assets	**26.1**				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 4.4	Modelled pricing	Third-party pricing	$18.85 - $74.05	$30.48
			Own credit risk	0.00% - 0.01%	0.01%
			Discount rate	0.02% - 0.05%	0.03%
	0.2	Modelled pricing	Third-party pricing	$21.51 - $78.42	$35.26
			Correlation factor	0.99% - 0.99%	0.99%
			Own credit risk	0.00% - 0.01%	0.01%
			Discount rate	0.02% - 0.11%	0.06%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	74.7	Modelled pricing	Third-party pricing	$1.04 - $7.76	$2.80
			Own credit risk	0.00% - 0.03%	0.00%
			Discount rate	0.00% - 0.08%	0.02%
	21.3	Modelled pricing	Third-party pricing	$1.07 - $7.75	$2.86
			Basis adjustment	-0.12% - 0.74%	0.18%
			Own credit risk	0.00% - 0.25%	0.00%
			Discount rate	0.00% - 0.07%	0.01%
Total liabilities	**100.6**				
Net assets (liabilities)	**$ (74.5)**				

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

As at	**March 31, 2016**		December 31, 2015	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$ 3,986.8**	**$ 4,579.7**	$ 4,008.6	$ 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.

16. REGULATORY ASSETS AND LIABILITIES

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

As at millions of Canadian dollars		**March 31** **2016**		**December 31** 2015
Regulatory assets				
Deferred income tax regulatory asset	**$**	**457.9**	$	431.3
Deferrals related to derivative instruments		**54.5**		67.7
Unamortized defeasance costs		**44.0**		45.7
2015 Demand side management deferral (note 5)		**35.6**		36.4
Stranded cost recovery		**27.5**		28.5
Pension and post-retirement medical plan		**10.8**		11.9
Regulated fuel adjustment mechanism (note 5)		**8.5**		13.7
Hydro-Quebec obligation		**7.0**		7.6
2014 Maine storms		**5.8**		6.1
Asset impairment recovery		**5.2**		5.5
Purchased power contracts		**4.9**		5.9
Stranded cost revenue & purchase power reconciliation deferrals		**4.6**		6.1
Other		**31.0**		33.1
	$	**697.3**	$	699.5
Current	**$**	**78.2**	$	94.2
Long-term		**619.1**		605.3
Total regulatory assets	**$**	**697.3**	$	699.5
Regulatory liabilities				
Deferrals related to derivative instruments	**$**	**131.3**	$	209.9
Self-Insurance Fund		**81.8**		86.8
Regulated fuel adjustment mechanism (note 5)		**55.1**		42.0
Deferred income tax regulatory liabilities		**16.3**		17.6
Other		**11.7**		14.3
	$	**296.2**	$	370.6
Current	**$**	**75.0**	$	98.9
Long-term		**221.2**		271.7
Total regulatory liabilities	**$**	**296.2**	$	**370.6**

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. Below are transactions between Emera and its associated companies reported in the Consolidated Statements of Income:

For the millions of Canadian dollars				Three months ended March 31
			2016	2015
	Nature of Service	**Presentation**		
Sales to:				
APUC subsidiary	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ 2.0**	$ 1.6
Purchases from:				
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**0.3**	$ 0.2
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**$ (8.1)**	(6.3)

Operating revenue – non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate-regulated subsidiaries of Emera totaling $0.3 million for the three months ended March 31, 2016 (2015 – $(0.2) million).

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

As at millions of Canadian dollars	March 31 2016	December 31 2015
Due from related parties:		
NSPML – current	**$ 1.2**	$ 1.6
Subsidiary of APUC – current	**0.3**	0.7
M&NP – loan receivable – long-term	**2.5**	2.5
Due to related parties:		
M&NP – current	**2.3**	2.1
Net due from (to) related parties	**$ 1.7**	$ 2.7

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.

18. OTHER CURRENT ASSETS

Other current assets consisted of the following:

As at millions of Canadian dollars	**March 31 2016**	December 31 2015
Net investment in direct financing lease	**$ 5.5**	$ 5.4
Dividend receivable	**6.5**	6.7
Capitalized transportation capacity (1)	**156.3**	222.7
	$ 168.3	$ 234.8

(1) Capitalized transportation capacity represents the value of transportation/storage received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

19. 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, Massachusetts, Rhode Island, Barbados, Dominica and Grand Bahama Island.

The net benefit cost of providing the defined benefit pension and non-pension benefit plans is detailed below:

For the millions of Canadian dollars		Three months ended March 31 **2016**		2015
Defined benefit pension plans				
Service cost	**$**	**5.5**	$	5.5
Interest cost		**15.1**		14.6
Expected return on plan assets		**(16.8)**		(16.0)
Current year amortization of:				
Actuarial losses (gains)		**10.5**		11.8
Past service costs (gains)		**(0.2)**		(0.2)
Total defined benefit pension plans		**14.1**		15.7
Non-pension benefits plan				
Service cost		**0.7**		0.8
Interest cost		**0.9**		1.0
Expected return on plan assets		**(0.1)**		-
Current year amortization of:				
Actuarial losses (gains)		**0.5**		0.3
Past service costs (gains)		**(2.1)**		(0.5)
Total non-pension benefits plans		**(0.1)**		1.6
Total defined benefit plans	**$**	**14.0**	$	17.3

20. 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, these investments include debt and equity investments related to Emera Reinsurance Limited, for captive insurance purposes.

Available-for-sale financial assets are measured at fair value and classified in the fair value hierarchy as

As at millions of Canadian dollars		**NAV (1)**		**Level 1**		**Level 2**		**Level 3**		**March 31 2016**
Common shares		-	**$**	**15.8**	**$**	**-**	**$**	**-**	**$**	**15.8**
Corporate bonds, debentures, short and medium term notes		-		**-**		**29.1**		**-**		**29.1**
Government bonds		-		**-**		**10.9**		**-**		**10.9**
Other investments measured at NAV		**50.4**								**50.4**
	$	**50.4**	**$**	**15.8**	**$**	**40.0**	**$**	**-**	**$**	**106.2**

As at millions of Canadian dollars		NAV (1)		Level 1		Level 2		Level 3		December 31 2015
Common shares	$	-	$	16.4	$	-	$	-	$	16.4
Corporate bonds, debentures, short and medium term notes		-		-		34.6		-		34.6
Government bonds		-		-		11.7		-		11.7
Other investments measured at NAV		53.3								53.3
	$	53.3	$	16.4	$	46.3	$	-	$	116.0

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

The fair value of financial instruments traded in active markets, and classified as level one, is based on quoted market prices at the balance sheet date. 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 primary pricing inputs in determining the equity and fixed assets mutual funds are the mutual funds' NAVs. The funds are open-ended mutual funds, and there are no trading restrictions on the funds.

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

As at millions of Canadian dollars	**March 31** **2016**	December 31 2015
Balance, beginning of the year	**$ 116.0**	$ 84.4
Additions	**-**	34.5
Disposals	**(3.5)**	(16.5)
	$ 112.5	$ 102.4
Change in fair value		
Gain (loss) recognized in other comprehensive income during the period	**(6.3)**	13.6
	$ (6.3)	$ 13.6
Balance, end of the period	**$ 106.2**	$ 116.0

There were no impairment provisions for available-for-sale investments for the three months ended March 31, 2016 (2015 - nil).

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

As at millions of Canadian dollars	**March 31** **2016**	December 31 2015
Maturity within 1 year	**$ 15.9**	$ 20.0
Maturity in 1-5 years	**24.1**	26.3
	$ 40.0	$ 46.3

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.

21. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	**March 31** **2016**	December 31 2015
Accrued charges	**$ 107.3**	$ 130.1
Accrued interest on long-term debt	**40.8**	44.1
Sales taxes payable	**13.6**	4.2
Accrued interest on convertible debentures represented by instalment receipts	**11.2**	11.2
Emission credits obligations (1)	**1.8**	6.3
Other	**8.0**	8.4
	$ 182.7	$ 204.3

(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 recorded as inventory (note 13) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

22. CONVERTIBLE DEBENTURES REPRESENTED BY INSTALMENT RECEIPTS

To finance a portion of the pending acquisition of TECO Energy, Emera, through a direct wholly owned subsidiary (the “Selling Debentureholder”), on September 28, 2015, completed the sale of $1.9 billion aggregate principal amount of 4.0 per cent convertible unsecured subordinated debentures, represented by instalment receipts.

On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures brought the aggregate proceeds of the Debenture Offering to $2.185 billion, assuming payment of the final instalment.

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.

Approximately $21.9 million ($15.1 million after-tax) (2015 – nil) in interest expense associated with the Debentures was recognized in Q1 2016.

For a detailed description of the terms of the Debentures, refer to Note 30 in Emera’s annual audit consolidated financial statements.

23. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consisted of the following:

As at millions of Canadian dollars		**March 31 2016**		December 31 2015
Funds received in excess of equity investment (1)	**$**	**209.5**	$	225.0
Long-term service agreements		**30.6**		37.7
Emission credits obligations (2)		**7.7**		6.3
Other		**24.5**		29.5
	$	**272.3**	$	298.5

(1) Emera has a 50 per cent investment in Bear Swamp. The investment balance in Bear Swamp is a credit primarily a result of a $178.7 million distribution received in Q4 2015.
(2) Throughout the three-year compliance period associated with the Regional Greenhouse Gas Initiative ("RGGI") 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 13) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

24. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at March 31, 2016, 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		2016	2017	2018	2019	2020	Thereafter	Total
Purchased power (1)	$	166.5 $	229.8 $	204.0 $	198.7	195.2 $	2,380.5 $	3,374.7
Solid fuel supply		114.5	75.7	12.0	-	-	-	202.2
DSM		22.1	34.0	34.9	-	-	-	91.0
Transportation (2)		188.9	118.6	78.2	43.2	41.1	86.3	556.3
Long-term service agreements (3)		48.6	49.6	34.4	47.1	20.4	202.1	402.2
Capital projects		69.2	5.6	-	-	-	-	74.8
Equity investment commitments (4)		356.0	183.0	-	-	-	-	539.0
Leases and other (5)		18.9	9.9	9.0	8.4	7.3	19.0	72.5
	$	984.7 $	706.2 $	372.5 $	297.4 $	264.0 $	2,687.9 $	5,312.7

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

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

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

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

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

B. Legal Proceedings

Emera

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

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

There is no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement.

Emera Maine

On September 30, 2011, a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users filed a complaint with the Federal Energy Regulatory Commission (“FERC”) alleging that the 11.14 per cent base return on equity (“ROE”) under the ISO-New England (“ISO-NE”) Open Access Transmission Tariff (“OATT”) was unjust and unreasonable. On June 19, 2014, the FERC issued an order in connection with this complaint, 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 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.

On March 22, 2016, the Administrative Law Judge ("ALJ") issued a recommended decision to the FERC with respect to the two outstanding ROE complaints (ENE Case and MA AG II Case). Each complaint was for a 15-month period commencing December 27, 2012 and July 31, 2014 respectively. The recommendation for the ENE Case was a 9.59 per cent base ROE, with a 10.42 per cent maximum ROE, and the recommendation for MA AG II Case was a 10.90 per cent base ROE, with a 12.19 per cent maximum ROE.

On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"), a collection of thirteen municipal light departments, seeking to reduce the base transmission ROE to a maximum of 8.93 per cent and the maximum ROE of 11.24 per cent.

Emera Maine has recorded a reserve of $5.8 million pre-tax ($4.5 million USD) (December 31, 2015 - $6.9 million or $5.0 million USD) for the first two base transmission ROE rate refund complaints. The reserves recorded for these complaints have been recorded as a component of Regulatory Liabilities on the Consolidated Balance Sheets, and the charges to earnings have been a reduction to Operating revenues - regulated on the Consolidated Statements of Income. The reserve was calculated on a 10.57 per cent base and represents Emera Maine's best estimate of the probable outcome. No update has been made to the reserve, as a result of the ALJ recommendation as it is pending approval by the FERC and is considered uncertain until that time. No reserve has been made as a result of the EMCOS complaint, as the outcome is considered uncertain.

Other Legal Proceedings

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

C. Environment

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. Emera estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations will be approximately $29.4 million during fiscal 2016 and are estimated to be $55.9 million from 2017 through 2020. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 24A. 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 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 March 31, 2016.

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 $40.1 million and, as at March 31, 2016, approximately $21.1 million (December 31, 2015 – $19.7 million) has been spent to date. NSPI has recognized an ARO of $14.9 million as at March 31, 2016 (December 31, 2015 – $15.0 million) associated with the PCB phase-out program.

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.

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.

On April 13, 2016, in association with a distribution rate application, the MPUC ordered an audit of Emera Maine's implementation of its new customer information system and customer service performance, including billing and reliability. The audit is expected to commence in Q2 2016 and conclude in the second half of 2016.

Changes in Environmental Legislation

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

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

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

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

Commercial Relationships

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

ENL

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

Interest Rate Risk

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

For the Company's regulated subsidiaries, the cost of debt is generally passed through to ratepayers. While regulatory ROE rates will generally and indirectly follow the direction of interest rates, regulatory ROE's are likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development initiatives.

The Company is subject to interest rate risk relating to certain sources of expected funds to effect the pending 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.

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 pending 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 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

There were no changes in Emera’s standby letters of credit since December 31, 2015.

25. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars	
Balance, December 31, 2015	147.21	$	2,157.5
Issuance of common stock (1)	0.06		2.7
Issued for cash under Purchase Plans at market rate	0.58		26.2
Discount on shares purchased under Dividend Reinvestment Plan	-		(1.2)
Options exercised under senior management share option plan	0.50		13.6
Stock-based compensation	-		0.2
Balance, March 31, 2016	**148.35**	**$**	**2,199.0**

(1) During the three months ended March 31 2016, Emera issued 0.06 million common shares to facilitate the creation and issuance of 0.2 million depositary receipts in connection with the ECI amalgamation transaction. The depositary receipts are listed on the Barbados Stock Exchange.

26. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars		**March 31 2016**		December 31 2015
ICDU	**$**	**48.8**	$	51.8
Preferred shares of GBPC		**33.5**		33.5
Domlec (1)		**22.5**		48.3
Preferred shares of Emera Maine		**0.4**		0.4
	$	**105.2**	$	134.0

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

27. VARIABLE INTEREST ENTITIES

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

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

For the three months ended March 31, 2016, the Company has identified the following significant VIEs:

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

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.

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

As at	**March 31, 2016**		December 31, 2015	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Consolidated VIE				
BLPC SIF	**$ 95.9**	**$ 95.9**	$ 101.4	$ 101.4
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**206.4**	**917.0**	187.6	1,007.0

28. COMPARATIVE INFORMATION

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

29. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through May 9, 2016, the date the financial statements were issued.