



ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

September 30, 2015

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>				
Revenues				
Commodity sales	6,562	6,599	17,768	22,089
Gas distribution sales	305	309	2,424	2,018
Transportation and other services	1,453	1,389	4,688	4,737
	8,320	8,297	24,880	28,844
Expenses				
Commodity costs	6,230	6,459	17,071	21,578
Gas distribution costs	143	149	1,807	1,332
Operating and administrative	1,097	805	3,016	2,364
Depreciation and amortization	524	392	1,483	1,151
Environmental costs, net of recoveries	2	62	(2)	103
Goodwill impairment <i>(Note 7)</i>	-	-	440	-
	7,996	7,867	23,815	26,528
Income from equity investments	324	430	1,065	2,316
Other expense	117	72	359	251
Interest expense	(331)	(220)	(630)	(143)
	(718)	(347)	(1,253)	(816)
Income taxes recovery/(expense) <i>(Note 13)</i>	(608)	(65)	(459)	1,608
	(129)	31	(76)	(362)
Earnings/(loss) from continuing operations	(737)	(34)	(535)	1,246
Discontinued operations <i>(Note 5)</i>				
Earnings from discontinued operations before income taxes	-	-	-	73
Income taxes from discontinued operations	-	-	-	(27)
Earnings from discontinued operations	-	-	-	46
Earnings/(loss)	(737)	(34)	(535)	1,292
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	200	20	334	(46)
Earnings/(loss) attributable to Enbridge Inc.	(537)	(14)	(201)	1,246
Preference share dividends	(72)	(66)	(214)	(180)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	(609)	(80)	(415)	1,066
Earnings/(loss) attributable to Enbridge Inc. common shareholders				
Earnings/(loss) from continuing operations	(609)	(80)	(415)	1,020
Earnings from discontinued operations, net of tax	-	-	-	46
	(609)	(80)	(415)	1,066
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders <i>(Note 9)</i>				
Continuing operations	(0.72)	(0.10)	(0.49)	1.23
Discontinued operations	-	-	-	0.06
	(0.72)	(0.10)	(0.49)	1.29
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders <i>(Note 9)</i>				
Continuing operations	(0.72)	(0.10)	(0.49)	1.21
Discontinued operations	-	-	-	0.06
	(0.72)	(0.10)	(0.49)	1.27

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2015	2014	2015	2014
<i>(unaudited; millions of Canadian dollars)</i>				
Earnings/(loss)	(737)	(34)	(535)	1,292
Other comprehensive income/(loss), net of tax				
Change in unrealized gains/(loss) on cash flow hedges	91	(96)	(129)	(610)
Change in unrealized loss on net investment hedges	(374)	(143)	(720)	(134)
Other comprehensive income/(loss) from equity investees	(5)	(3)	17	4
Reclassification to earnings of realized cash flow hedges	14	(13)	24	62
Reclassification to earnings of unrealized cash flow hedges	(17)	100	(53)	124
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	9	3	22	6
Change in foreign currency translation adjustment	1,392	671	2,685	687
Reclassification to earnings of derecognized cash flow hedges <i>(Note 12)</i>	(247)	-	(247)	-
Other comprehensive income	863	519	1,599	139
Comprehensive income	126	485	1,064	1,431
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	229	(94)	275	(67)
Comprehensive income attributable to Enbridge Inc.	355	391	1,339	1,364
Preference share dividends	(72)	(66)	(214)	(180)
Comprehensive income attributable to Enbridge Inc. common shareholders	283	325	1,125	1,184

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Nine months ended September 30,	
	2015	2014
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>		
Preference shares		
Balance at beginning of period	6,515	5,141
Preference shares issued	-	1,374
Balance at end of period	6,515	6,515
Common shares		
Balance at beginning of period	6,669	5,744
Shares issued	-	446
Dividend reinvestment and share purchase plan	486	315
Shares issued on exercise of stock options	64	40
Balance at end of period	7,219	6,545
Additional paid-in capital		
Balance at beginning of period	2,549	746
Drop down of interest to Enbridge Energy Partners, L.P. (Note 11)	218	-
Stock-based compensation	30	25
Options exercised	(16)	(11)
Issuance of treasury stock	-	22
Enbridge Energy Partners, L.P. equity restructuring	-	1,584
Drop down of interest to Midcoast Energy Partners, L.P.	-	(18)
Dilution gains and other	35	5
Balance at end of period	2,816	2,353
Retained earnings		
Balance at beginning of period	1,571	2,550
Earnings/(loss) attributable to Enbridge Inc.	(201)	1,246
Preference share dividends	(214)	(180)
Common share dividends declared	(1,195)	(880)
Dividends paid to reciprocal shareholder	17	13
Redemption value adjustment attributable to redeemable noncontrolling interests	440	(364)
Balance at end of period	418	2,385
Accumulated other comprehensive income/(loss) (Note 10)		
Balance at beginning of period	(435)	(599)
Other comprehensive income attributable to Enbridge Inc. common shareholders	1,540	118
Balance at end of period	1,105	(481)
Reciprocal shareholding		
Balance at beginning of period	(83)	(86)
Issuance of treasury stock	-	3
Balance at end of period	(83)	(83)
Total Enbridge Inc. shareholders' equity	17,990	17,234
Noncontrolling interests		
Balance at beginning of period	2,015	4,014
Earnings/(loss) attributable to noncontrolling interests	(339)	46
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	(149)	(144)
Change in foreign currency translation adjustment	240	95
Reclassification to earnings of realized cash flow hedges	(10)	21
Reclassification to earnings of unrealized cash flow hedges	(17)	58
	64	30
Comprehensive income attributable to noncontrolling interests	(275)	76
Distributions	(501)	(395)
Contributions	612	163
Drop down of interest to Enbridge Energy Partners, L.P. (Note 11)	(304)	-
Dilution loss	(53)	-
Enbridge Energy Partners, L.P. equity restructuring	-	(2,330)
Drop down of interest to Midcoast Energy Partners, L.P.	-	39
Disposition of Frontier Pipeline Company (Note 5)	(7)	-
Other	(1)	2
Balance at end of period	1,486	1,569
Total equity	19,476	18,803
Dividends paid per common share	1.395	1.050

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
<i>(unaudited; millions of Canadian dollars)</i>				
Operating activities				
Earnings/(loss)	(737)	(34)	(535)	1,292
Earnings from discontinued operations	-	-	-	(46)
Depreciation and amortization	524	392	1,483	1,151
Deferred income taxes (recovery)/expense	98	(14)	(41)	332
Changes in unrealized (gains)/loss on derivative instruments, net	1,279	419	2,410	56
Cash distributions in excess of equity earnings	54	90	180	139
Impairment <i>(Note 7)</i>	-	-	456	-
Gain on disposition	(60)	-	(94)	(16)
Hedge ineffectiveness	(21)	130	(51)	161
Inventory revaluation allowance	216	2	261	4
Other	(4)	71	(90)	106
Changes in regulatory assets and liabilities	21	(4)	53	11
Changes in environmental liabilities, net of recoveries	(15)	(11)	(35)	(47)
Changes in operating assets and liabilities	(450)	(295)	(232)	(1,271)
Cash provided by continuing operations	905	746	3,765	1,872
Cash provided by discontinued operations <i>(Note 5)</i>	-	-	-	19
	905	746	3,765	1,891
Investing activities				
Additions to property, plant and equipment	(1,747)	(2,354)	(5,310)	(7,397)
Long-term investments	(132)	(168)	(311)	(693)
Additions to intangible assets	(27)	(42)	(89)	(153)
Acquisition	-	-	(106)	-
Proceeds from disposition	112	62	146	81
Affiliate loans, net	48	3	54	9
Changes in restricted cash	-	(26)	(21)	(5)
Cash used in continuing operations	(1,746)	(2,525)	(5,637)	(8,158)
Cash provided by discontinued operations <i>(Note 5)</i>	-	-	-	4
	(1,746)	(2,525)	(5,637)	(8,154)
Financing activities				
Net change in bank indebtedness and short-term borrowings	(88)	191	(639)	635
Net change in commercial paper and credit facility draws	208	381	2,444	1,596
Debenture and term note issues	1,554	878	1,554	4,334
Debenture and term note repayments	(603)	(200)	(998)	(825)
Southern Lights credit facility repayments	-	(1,507)	-	(1,507)
Debenture and term note issues - Southern Lights	-	1,507	-	1,507
Contributions from noncontrolling interests	33	82	612	163
Distributions to noncontrolling interests	(177)	(135)	(501)	(395)
Distributions to redeemable noncontrolling interests	(27)	(18)	(80)	(55)
Preference shares issued	-	607	-	1,365
Common shares issued	7	64	47	470
Preference share dividends	(72)	(63)	(214)	(174)
Common share dividends	(230)	(193)	(709)	(565)
	605	1,594	1,516	6,549
Effect of translation of foreign denominated cash and cash equivalents	51	25	119	26
Increase/(decrease) in cash and cash equivalents	(185)	(160)	(237)	312
Cash and cash equivalents at beginning of period - discontinued operations	-	-	-	20
Cash and cash equivalents at beginning of period - continuing operations	1,209	1,248	1,261	756
Cash and cash equivalents at end of period	1,024	1,088	1,024	1,088

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

September 30, December 31,
2015 2014

(unaudited; millions of Canadian dollars; number of shares in millions)

	September 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	1,024	1,261
Restricted cash	68	47
Accounts receivable and other (Note 6)	5,043	5,504
Accounts receivable from affiliates	5	241
Inventory	1,491	1,148
	7,631	8,201
Property, plant and equipment, net	61,995	53,830
Long-term investments	6,520	5,408
Deferred amounts and other assets	3,198	3,208
Intangible assets, net	1,296	1,166
Goodwill (Note 7)	78	483
Deferred income taxes	852	561
	81,570	72,857
Liabilities and equity		
Current liabilities		
Bank indebtedness	369	507
Short-term borrowings	540	1,041
Accounts payable and other	7,242	6,444
Accounts payable to affiliates	57	80
Interest payable	334	264
Environmental liabilities	146	161
Current maturities of long-term debt (Note 8)	767	1,004
	9,455	9,501
Long-term debt (Note 8)	38,927	33,423
Other long-term liabilities	6,369	4,041
Deferred income taxes	5,615	4,842
	60,366	51,807
Contingencies (Note 15)		
Redeemable noncontrolling interests	1,728	2,249
Equity		
Share capital		
Preference shares	6,515	6,515
Common shares (864 and 852 outstanding at September 30, 2015 and December 31, 2014, respectively)	7,219	6,669
Additional paid-in capital	2,816	2,549
Retained earnings	418	1,571
Accumulated other comprehensive income/(loss) (Note 10)	1,105	(435)
Reciprocal shareholding	(83)	(83)
Total Enbridge Inc. shareholders' equity	17,990	16,786
Noncontrolling interests	1,486	2,015
	19,476	18,801
	81,570	72,857

See accompanying notes to the unaudited interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2014. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, with the exception of certain out-of-period adjustments further described in Note 4, Segmented Information, which management considers necessary to present fairly the Company's financial position as at September 30, 2015 and results of operations and cash flows for the three and nine months ended September 30, 2015 and 2014. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's consolidated financial statements as at and for the year ended December 31, 2014, except for the adoption of new standards (Note 3). Amounts are stated in Canadian dollars unless otherwise noted.

The Company's operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility business, as well as other factors such as the supply of and demand for crude oil and natural gas.

2. CANADIAN RESTRUCTURING PLAN

Effective September 1, 2015, under an agreement with Enbridge Income Fund (the Fund) and Enbridge Income Fund Holdings Inc. (ENF), Enbridge transferred its Canadian Liquids Pipelines business, held by Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines Athabasca Inc. (EPAI), and certain Canadian renewable energy assets to the Fund Group (comprising the Fund, Enbridge Commercial Trust (ECT), Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) for consideration valued at \$30.4 billion plus incentive distribution and performance rights. The consideration that Enbridge received included \$18.7 billion of units in the Fund Group, comprised of \$3 billion of Fund units and \$15.7 billion of equity units of EIPLP, in which the Fund has an interest. The Fund Group also assumed debt of EPI and EPAI of approximately \$11.7 billion. Upon closing of the transaction, Enbridge's overall economic interest in the Fund Group increased to 91.9%. Also effective September 1, 2015, the transferred businesses and assets noted above are reported under the Sponsored Investments segment as further described below.

LIQUIDS PIPELINES

Until August 31, 2015, Liquids Pipelines consisted of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Seaway Crude Pipeline System, Flanagan South Pipeline, Southern Lights Pipeline, Spearhead Pipeline and Feeder Pipelines and Other. Effective September 1, 2015, under the agreement described above, Enbridge transferred to the Fund Group the Canadian Mainline, Regional Oil Sands System, the Canadian portion of the Southern Lights Pipeline and certain residual rights and/or obligations relating to certain terminal and storage assets. These transferred assets are reported under the Sponsored Investments segment from the date of transfer.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services continues to consist of investments in natural gas pipelines, gathering and processing facilities and the Company's energy services businesses, along with renewable energy and transmission facilities. Effective September 1, 2015, under the agreement described above, Enbridge transferred to the Fund Group certain Canadian renewable energy assets which are reported under the Sponsored Investments segment from the date of transfer.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 33.7% economic interest in Enbridge Energy Partners, L.P. (EEP) and Enbridge's interests in both the Eastern Access and Lakehead System Mainline Expansion projects held through Enbridge Energy, Limited Partnership. Also within Sponsored Investments is the Company's overall 91.9% economic interest in the Fund Group. Enbridge, through its subsidiaries, manages the day-to-day operations of and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

As a result of the Canadian Restructuring Plan, as discussed above, effective September 1, 2015, the Fund Group's primary operations include its liquids pipelines business, which includes the Canadian Mainline and Regional Oil Sands System, its renewable power generation assets and a natural gas transmission business through its 50% interest in Alliance Pipeline.

3. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Principles of Consolidation and Noncontrolling Interests

As a result of the Canadian Restructuring plan, ECT, a subsidiary of the Company, determines its equity investment earnings from EIPLP using the Hypothetical Liquidation at Book Value (HLBV) method. ECT applies the HLBV method to its equity method investments where cash distributions, including both preference and residual distributions, are not based on the investor's ownership percentages. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that ECT would receive if EIPLP were to liquidate all of its assets, as valued in accordance with U.S. GAAP, and distribute that cash to the investors. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is ECT's share of the earnings or losses from the equity investment for the period.

While ECT and EIPLP are both consolidated in these financial statements, the use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on Enbridge's Consolidated Statements of Earnings. The Company continues to recognize Redeemable noncontrolling interests on the Consolidated Statements of Financial Position at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

Effective January 1, 2015, the Company prospectively adopted Accounting Standards Update (ASU) 2014-08 which changes the criteria and disclosures for reporting discontinued operations. The revised criteria will in general, result in fewer transactions being categorized as discontinued operations. There was no material impact to the consolidated financial statements as a result of adopting this update.

Extraordinary and Unusual Items

Effective January 1, 2015, the Company retrospectively adopted ASU 2015-01 which eliminates the concept of extraordinary items from U.S. GAAP. Entities will no longer be required to separately classify and present extraordinary items in the Consolidated Statements of Earnings. There was no material impact to the Company's consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Measurement Date of Defined Benefit Obligation and Plan Assets

ASU 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. For entities with a fiscal year end that does not coincide with a month end, the new standard permits an entity to measure its defined benefit plan assets and obligations using the month end that is closest to the entity's fiscal year end. In addition, where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is also permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby an entity may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Amendments to the Consolidation Analysis

ASU 2015-02, issued in February 2015, revises the current consolidation guidance which results in a change in the determination of whether an entity consolidates certain types of legal entities. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied on a full or modified retrospective basis.

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 and may be applied on either a full or modified retrospective basis.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations

ASU 2015-16 was issued in September 2015 with the intent to simplify the accounting for measurement-period adjustments in business combinations. The new standard requires that an acquirer must recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The accounting update is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

4. SEGMENTED INFORMATION

Three months ended September 30, 2015 <i>(millions of Canadian dollars)</i>	Liquids Pipelines ²	Gas Distribution	Gas Pipelines, Processing and Energy Services ²	Sponsored Investments ²	Corporate ¹	Consolidated
Revenues	263	388	5,842	1,827	-	8,320
Commodity and gas distribution costs	(1)	(156)	(5,555)	(663)	2	(6,373)
Operating and administrative	(323)	(131)	(56)	(581)	(6)	(1,097)
Depreciation and amortization	(141)	(73)	(45)	(254)	(11)	(524)
Environmental costs, net of recoveries	-	-	-	(2)	-	(2)
Goodwill impairment	-	-	-	-	-	-
	(202)	28	186	327	(15)	324
Income/(loss) from equity investments	83	-	(3)	51	(14)	117
Other income/(expense)	41	-	4	(27)	(349)	(331)
Interest expense	(140)	(44)	(27)	(175)	(332)	(718)
Income taxes recovery/(expense)	(28)	14	(65)	(270)	220	(129)
Earnings/(loss)	(246)	(2)	95	(94)	(490)	(737)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	9	181	11	200
Preference share dividends	-	-	-	-	(72)	(72)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	(247)	(2)	104	87	(551)	(609)
Additions to property, plant and equipment ³	1,038	205	51	443	10	1,747

Three months ended September 30, 2014 <i>(millions of Canadian dollars)</i>	Liquids Pipelines ²	Gas Distribution	Gas Pipelines, Processing and Energy Services ²	Sponsored Investments ²	Corporate ¹	Consolidated
Revenues	382	354	5,355	2,206	-	8,297
Commodity and gas distribution costs	-	(150)	(5,122)	(1,336)	-	(6,608)
Operating and administrative	(270)	(129)	(52)	(351)	(3)	(805)
Depreciation and amortization	(123)	(53)	(47)	(164)	(5)	(392)
Environmental costs, net of recoveries	(7)	-	-	(55)	-	(62)
	(18)	22	134	300	(8)	430
Income/(loss) from equity investments	35	-	33	20	(16)	72
Other income/(expense)	(9)	(5)	(1)	12	(217)	(220)
Interest expense	(86)	(43)	(29)	(176)	(13)	(347)
Income taxes recovery/(expense)	48	15	(49)	(69)	86	31
Earnings/(loss)	(30)	(11)	88	87	(168)	(34)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	21	-	20
Preference share dividends	-	-	-	-	(66)	(66)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	(31)	(11)	88	108	(234)	(80)
Additions to property, plant and equipment ³	1,287	99	134	817	18	2,355

Nine months ended September 30, 2015	Gas Pipelines, Processing and Energy Services ²					Sponsored Investments ²	Corporate ¹	Consolidated
	Liquids Pipelines ²	Gas Distribution	Gas Pipelines, Processing and Energy Services ²	Sponsored Investments ²	Corporate ¹			
<i>(millions of Canadian dollars)</i>								
Revenues	1,422	2,806	15,246	5,406	-	-	24,880	
Commodity and gas distribution costs	(5)	(1,852)	(14,600)	(2,421)	-	-	(18,878)	
Operating and administrative	(1,074)	(399)	(180)	(1,354)	(9)	-	(3,016)	
Depreciation and amortization	(449)	(230)	(140)	(642)	(22)	-	(1,483)	
Environmental costs, net of recoveries	4	-	-	(2)	-	-	2	
Goodwill impairment	-	-	-	(440)	-	-	(440)	
Income/(loss) from equity investments	(102)	325	326	547	(31)	-	1,065	
Other income/(expense)	228	-	(1)	150	(18)	-	359	
Interest expense	29	(2)	22	(31)	(648)	-	(630)	
Income taxes recovery/(expense)	(454)	(126)	(85)	(384)	(204)	-	(1,253)	
Earnings/(loss)	41	(21)	(103)	(410)	417	-	(76)	
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(258)	176	159	(128)	(484)	-	(535)	
Preference share dividends	(2)	-	15	310	11	-	334	
Earnings/(loss) attributable to Enbridge Inc. common shareholders	-	-	-	-	(214)	-	(214)	
Additions to property, plant and equipment ³	(260)	176	174	182	(687)	-	(415)	

Nine months ended September 30, 2014	Gas Pipelines, Processing and Energy Services ²					Sponsored Investments ²	Corporate ¹	Consolidated
	Liquids Pipelines ²	Gas Distribution	Gas Pipelines, Processing and Energy Services ²	Sponsored Investments ²	Corporate ¹			
<i>(millions of Canadian dollars)</i>								
Revenues	1,820	2,268	18,063	6,693	-	-	28,844	
Commodity and gas distribution costs	-	(1,333)	(17,291)	(4,286)	-	-	(22,910)	
Operating and administrative	(805)	(399)	(136)	(1,015)	(9)	-	(2,364)	
Depreciation and amortization	(361)	(225)	(82)	(469)	(14)	-	(1,151)	
Environmental costs, net of recoveries	-	-	-	(103)	-	-	(103)	
Income/(loss) from equity investments	654	311	554	820	(23)	-	2,316	
Other income/(expense)	110	-	111	55	(25)	-	251	
Interest income/(expense)	(6)	(3)	8	10	(152)	-	(143)	
Income taxes recovery/(expense)	(260)	(123)	(72)	(397)	36	-	(816)	
Earnings/(loss) from continuing operations	(51)	(41)	(215)	(166)	111	-	(362)	
Discontinued operations	447	144	386	322	(53)	-	1,246	
Earnings from discontinued operations before income tax	-	-	73	-	-	-	73	
Income taxes from discontinued operations	-	-	(27)	-	-	-	(27)	
Earnings from discontinued operations	-	-	46	-	-	-	46	
Earnings/(loss)	447	144	432	322	(53)	-	1,292	
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	-	-	(43)	-	-	(46)	
Preference share dividends	-	-	-	-	(180)	-	(180)	
Earnings/(loss) attributable to Enbridge Inc. common shareholders	444	144	432	279	(233)	-	1,066	
Additions to property, plant and equipment ³	4,301	307	463	2,286	42	-	7,399	

1 Included within the Corporate segment was Interest income of \$203 million and \$625 million for the three and nine months ended September 30, 2015, respectively (2014 - \$182 million and \$498 million, respectively) charged to other operating segments.

2 Effective September 1, 2015, Enbridge transferred its Canadian Liquids Pipelines businesses and certain Canadian renewable energy assets to the Fund Group within the Sponsored Investments segment as described under the Canadian Restructuring Plan (Note 2). Revenues of (\$53) million and \$603 million and loss of \$350 million and \$403 million in the three and nine month periods ended September 30, 2015, respectively (2014 - revenues of \$237 million and \$1,402 million and loss of \$59 million and earnings of \$349 million, respectively, in the three and nine month periods) which relate to Liquids Pipelines assets prior to the transfer have not been reclassified into the Sponsored Investments segment for presentation purposes. Revenues of \$17 million and \$83 million and earnings of \$1 million and \$1 million in the three and nine month periods ended September 30, 2015, respectively (2014 - revenues of \$23 million and \$61 million and loss of \$3 million and \$8 million, respectively, in the three and nine month periods) which relate to Gas Pipelines, Processing and Energy Services assets prior to the transfer have not been reclassified into the Sponsored Investments segment for presentation purposes.

3 Includes allowance for equity funds used during construction.

OUT-OF-PERIOD ADJUSTMENTS

Earnings attributable to Enbridge Inc. common shareholders for the nine months ended September 30, 2015 were increased by an out-of-period adjustment of \$71 million within the Corporate segment in respect of an overstatement of deferred income tax expense in 2013 and 2014.

For the three months ended September 30, 2014, Commodity sales revenues and Commodity costs were increased by a non-cash out-of-period adjustment of \$174 million. The adjustment related to understatement of Commodity sales revenues and Commodity costs for the first half of 2014 and had no impact on earnings.

TOTAL ASSETS

	September 30, 2015	December 31, 2014
<i>(millions of Canadian dollars)</i>		
Liquids Pipelines ¹	12,052	27,657
Gas Distribution	9,227	9,320
Gas Pipelines, Processing and Energy Services ¹	7,821	7,601
Sponsored Investments ¹	48,226	23,515
Corporate	4,244	4,764
	81,570	72,857

¹ Effective September 1, 2015, Enbridge transferred its Canadian Liquids Pipelines businesses and certain Canadian renewable energy assets to the Fund Group within the Sponsored Investments segment as described under the Canadian Restructuring Plan (Note 2). Liquids Pipelines assets as at December 31, 2014 of \$17,782 million and Gas Pipelines, Processing and Energy Services assets as at December 31, 2014 of \$1,123 million have not been reclassified into the Sponsored Investments segment for presentation purposes.

5. ACQUISITION AND DISPOSITIONS

ACQUISITION

Magic Valley and Wildcat Wind Farms

Subsequent to the December 31, 2014 acquisition of an 80% controlling interest in Magic Valley and Wildcat wind farms, the Company completed the valuation of the acquired assets, resulting in no change to the purchase price allocation previously disclosed. The wind farms are included within the Gas Pipelines, Processing and Energy Services segment.

OTHER DISPOSITIONS

In August 2015, the Company sold its 77.8% controlling interest in the Frontier Pipeline Company, including certain non-core pipeline assets located in the midwest United States, to two unrelated parties for gross proceeds of \$112 million (US\$85 million). A gain of \$70 million (US\$53 million) was presented within Other expense on the Consolidated Statements of Earnings. These amounts are included within the Liquids Pipelines segment.

In May 2015, the Fund sold certain of its crude oil pipeline system assets to an unrelated party for gross proceeds of \$26 million. A gain of \$22 million was presented within Other expense on the Consolidated Statements of Earnings.

DISCONTINUED OPERATIONS

In March 2014, the Company completed the sale of certain of its Enbridge Offshore Pipelines assets located within the Stingray corridor to an unrelated third party for cash proceeds of \$11 million (US\$10 million), subject to working capital adjustments. The gain of \$70 million (US\$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of \$59 million (US\$53 million), is presented as Earnings from discontinued operations for the nine months ended September 30, 2014. The results of operations, including revenues of \$4 million and related cash flows, have also been presented as discontinued operations for the nine months ended September 30, 2014. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

6. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain EEP subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US\$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US\$341 million (\$457 million) and US\$378 million (\$439 million) as at September 30, 2015 and December 31, 2014, respectively.

7. GOODWILL

During the second quarter of 2015, the Company recorded an impairment charge of \$440 million (\$167 million after-tax attributable to Enbridge) related to EEP's natural gas and NGL businesses, which EEP holds directly and indirectly through its partially-owned subsidiary, Midcoast Energy Partners, L.P. Due to a prolonged decline in commodity prices, reduction in producers' expected drilling programs negatively impacted forecasted cash flows from EEP's natural gas and NGL systems. This change in circumstance led to the completion of an impairment test, resulting in a full impairment of goodwill on EEP's natural gas and NGL businesses.

In performing the impairment assessment, EEP measured the fair value of its reporting units primarily by using a discounted cash flow analysis and it also considered overall market capitalization of its business, cash flow measurement data and other factors. EEP's estimate of fair value required it to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of its reporting units.

8. DEBT

During the nine months ended September 30, 2015, the Company completed aggregate issuances of unsecured, medium-term notes of \$1,570 million. These aggregate issuances carry interest rates ranging from approximately 3.3% to 4.5% and have maturities ranging from 10 to 30 years.

Subsequent to September 30, 2015, the Company completed aggregate issuances of senior unsecured notes of US\$1,600 million. These aggregate issuances carry interest rates ranging from approximately 4.4% to 7.4% and have maturities ranging from five to 30 years.

CREDIT FACILITIES

The following table provides details of the Company's committed credit facilities as at September 30, 2015 and December 31, 2014.

	Maturity Dates	September 30, 2015			December 31, 2014
		Total Facilities	Draws ¹	Available	Total Facilities
<i>(millions of Canadian dollars)</i>					
Liquids Pipelines	2017	3,027	1,180	1,847	300
Gas Distribution	2017-2019	1,009	543	466	1,008
Sponsored Investments	2017-2019	5,072	3,796	1,276	4,531
Corporate	2016-2020	12,390	7,409	4,981	12,772
Total committed credit facilities		21,498	12,928	8,570	18,611

¹ Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

In addition to the committed credit facilities noted above, the Company also has \$401 million (December 31, 2014 - \$361 million) of uncommitted demand credit facilities, of which \$50 million (December 31, 2014 - \$80 million) was unutilized as at September 30, 2015.

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2016 to 2020.

Commercial paper and credit facility draws, net of short-term borrowings, of \$12,084 million (December 31, 2014 - \$8,960 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

9. EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2014 - 12 million) for the three and nine months ended September 30, 2015, resulting from the Company's reciprocal investment in Noverco Inc.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
<i>(number of shares in millions)</i>				
Weighted average shares outstanding	849	835	845	826
Effect of dilutive options	10	12	12	11
Diluted weighted average shares outstanding	859	847	857	837

For the three and nine months ended September 30, 2015, 8,876,940 and 6,878,620 anti-dilutive stock options with a weighted average exercise price of \$54.08 and \$57.59, respectively (2014 - nil and 5,920,500 with a weighted average exercise price of nil and \$48.78, respectively) were excluded from the diluted earnings per common share calculation.

10. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in Accumulated other comprehensive income/(loss) (AOCI) attributable to Enbridge common shareholders for the nine months ended September 30, 2015 and 2014 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
<i>(millions of Canadian dollars)</i>						
Balance at January 1, 2015	(488)	108	309	(5)	(359)	(435)
Other comprehensive income/(loss) retained in AOCI	7	(759)	2,427	35	-	1,710
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts ¹	(14)	-	-	-	-	(14)
Commodity contracts ²	(10)	-	-	-	-	(10)
Foreign exchange contracts ³	6	-	-	-	-	6
Other contracts ⁴	22	-	-	-	-	22
Amortization of pension and OPEB actuarial loss and prior service cost ⁵	-	-	-	-	26	26
Other comprehensive loss reclassified to earnings of derecognized cash flow hedges <i>(Note 12)</i>	(338)	-	-	-	-	(338)
	(327)	(759)	2,427	35	26	1,402
Tax impact						
Income tax on amounts retained in AOCI	20	39	-	(2)	-	57
Income tax on amounts reclassified to earnings	(6)	-	-	-	(4)	(10)
Income tax on amounts reclassified to earnings of derecognized cash flow hedges <i>(Note 12)</i>	91	-	-	-	-	91
	105	39	-	(2)	(4)	138
Balance at September 30, 2015	(710)	(612)	2,736	28	(337)	1,105

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
<i>(millions of Canadian dollars)</i>						
Balance at January 1, 2014	(1)	378	(778)	(15)	(183)	(599)
Other comprehensive income/(loss) retained in AOCI	(628)	(155)	592	4	-	(187)
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts ¹	150	-	-	-	-	150
Commodity contracts ²	8	-	-	-	-	8
Foreign exchange contracts ³	10	-	-	-	-	10
Other contracts ⁴	(29)	-	-	-	-	(29)
Amortization of pension and OPEB actuarial loss and prior service cost ⁵	-	-	-	-	10	10
	(489)	(155)	592	4	10	(38)
Tax impact						
Income tax on amounts retained in AOCI	171	21	-	-	-	192
Income tax on amounts reclassified to earnings	(32)	-	-	-	(4)	(36)
	139	21	-	-	(4)	156
Balance at September 30, 2014	(351)	244	(186)	(11)	(177)	(481)

¹ Reported within Interest expense in the Consolidated Statements of Earnings.

² Reported within Commodity sales and Commodity costs in the Consolidated Statements of Earnings.

³ Reported within Other expense in the Consolidated Statements of Earnings.

⁴ Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

⁵ These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

11. NONCONTROLLING INTERESTS

ALBERTA CLIPPER DROP DOWN

On January 2, 2015, Enbridge transferred its 66.7% interest in the United States segment of the Alberta Clipper pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP for aggregate consideration of \$1.1 billion (US\$1 billion), consisting of approximately \$814 million (US\$694 million) of Class E equity units issued to Enbridge by EEP and the repayment of approximately \$359 million (US\$306 million) of indebtedness owed to Enbridge. Prior to the transfer, EEP owned the remaining 33.3% interest in the United States segment of the Alberta Clipper pipeline.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A units held by the public and are convertible into Class A units on a one-for-one basis at Enbridge's option. The transaction applies to all distributions declared subsequent to the transfer. The Class E units are redeemable at EEP's option after 30 years, if not converted by Enbridge prior to that time. The units have a liquidation preference equal to their notional value at December 23, 2014 of US\$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units. Enbridge's economic interest in EEP increased from 33.7% to 36.6% as a result of the transfer. EEP recorded the Class E units at fair value. As a result, the Company recorded a decrease in Noncontrolling interests of \$304 million and increases in Additional paid-in capital and Deferred income tax liabilities of \$218 million and \$86 million, respectively.

EEP ISSUANCE OF CLASS A UNITS

In March 2015, EEP completed a listed share issuance. The Company participated only to the extent to maintain its 2% General Partner interest, resulting in a decrease in the overall economic interest from 36.6% to 35.9%. The listed share issuance resulted in contributions of \$366 million (US\$289 million) from noncontrolling interest holders.

In addition to its economic interest, Enbridge also holds interest in the preferred units of EEP.

REDEEMABLE NONCONTROLLING INTERESTS

Redeemable noncontrolling interests in the Fund at September 30, 2015 represented 34.3% (December 31, 2014 - 70.6%; September 30, 2014 - 68.6%) of interests in the Fund's trust units that are held by third parties. The decrease from 70.6% at December 31, 2014 to 34.3% at September 30, 2015 represented an increase in Enbridge's unit holdings in the Fund resulting from the September 1, 2015 closing of the Canadian Restructuring Plan (*Note 2*).

12. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income/(loss) (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company generates certain revenues, incurs expenses, and holds a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 3.8%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt within its Board of Directors approved policy limit of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company primarily uses qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of its ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based

compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at September 30, 2015 or December 31, 2014.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances. The following table also summarizes the maximum potential settlement in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
September 30, 2015						
<i>(millions of Canadian dollars)</i>						
Accounts receivable and other						
Foreign exchange contracts	5	3	2	10	(4)	6
Interest rate contracts	-	-	-	-	-	-
Commodity contracts	10	-	579	589	(160)	429
Other contracts	-	-	3	3	(2)	1
	15	3	584	602	(166)	436
Deferred amounts and other assets						
Foreign exchange contracts	101	6	-	107	(106)	1
Interest rate contracts	1	-	-	1	-	1
Commodity contracts	14	-	166	180	(93)	87
	116	6	166	288	(199)	89
Accounts payable and other						
Foreign exchange contracts	(1)	(75)	(638)	(714)	4	(710)
Interest rate contracts	(576)	-	(83)	(659)	-	(659)
Commodity contracts	-	-	(465)	(465)	138	(327)
Other contracts	-	-	(2)	(2)	2	-
	(577)	(75)	(1,188)	(1,840)	144	(1,696)
Other long-term liabilities						
Foreign exchange contracts	-	(244)	(2,718)	(2,962)	106	(2,856)
Interest rate contracts	(651)	-	(341)	(992)	-	(992)
Commodity contracts	-	-	(271)	(271)	93	(178)
Other contracts	(9)	-	(5)	(14)	-	(14)
	(660)	(244)	(3,335)	(4,239)	199	(4,040)
Total net derivative asset/(liability)						
Foreign exchange contracts	105	(310)	(3,354)	(3,559)	-	(3,559)
Interest rate contracts	(1,226)	-	(424)	(1,650)	-	(1,650)
Commodity contracts	24	-	9	33	(22) ¹	11
Other contracts	(9)	-	(4)	(13)	-	(13)
	(1,106)	(310)	(3,773)	(5,189)	(22)	(5,211)

¹ Amount available for offset includes \$22 million of cash collateral.

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
<i>(millions of Canadian dollars)</i>						
Accounts receivable and other						
Foreign exchange contracts	3	7	3	13	(13)	-
Interest rate contracts	8	-	-	8	(7)	1
Commodity contracts	34	-	501	535	(130)	405
Other contracts	4	-	8	12	-	12
	49	7	512	568	(150)	418
Deferred amounts and other assets						
Foreign exchange contracts	33	18	-	51	(51)	-
Interest rate contracts	5	-	-	5	(5)	-
Commodity contracts	17	-	118	135	(43)	92
Other contracts	5	-	3	8	-	8
	60	18	121	199	(99)	100
Accounts payable and other						
Foreign exchange contracts	(3)	(80)	(218)	(301)	13	(288)
Interest rate contracts	(438)	-	-	(438)	7	(431)
Commodity contracts	-	-	(281)	(281)	97	(184)
	(441)	(80)	(499)	(1,020)	117	(903)
Other long-term liabilities						
Foreign exchange contracts	-	(49)	(1,147)	(1,196)	51	(1,145)
Interest rate contracts	(576)	-	-	(576)	5	(571)
Commodity contracts	-	-	(306)	(306)	43	(263)
	(576)	(49)	(1,453)	(2,078)	99	(1,979)
Total net derivative asset/(liability)						
Foreign exchange contracts	33	(104)	(1,362)	(1,433)	-	(1,433)
Interest rate contracts	(1,001)	-	-	(1,001)	-	(1,001)
Commodity contracts	51	-	32	83	(33) ¹	50
Other contracts	9	-	11	20	-	20
	(908)	(104)	(1,319)	(2,331)	(33)	(2,364)

¹ Amount available for offset includes \$33 million of cash collateral.

The following table summarizes the maturity and notional principal or quantity outstanding related to the Company's derivative instruments.

September 30, 2015	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase <i>(millions of United States dollars)</i>	200	28	413	2	2	2
Foreign exchange contracts - United States dollar forwards - sell <i>(millions of United States dollars)</i>	1,139	3,002	3,104	3,150	2,645	3,105
Foreign exchange contracts - Euro forwards - purchase <i>(millions of Euros)</i>	-	-	-	-	-	-
Interest rate contracts - short-term borrowings <i>(millions of Canadian dollars)</i>	1,599	8,441	7,469	3,859	346	505
Interest rate contracts - long-term debt <i>(millions of Canadian dollars)</i>	2,861	2,572	2,560	1,239	767	-
Equity contracts <i>(millions of Canadian dollars)</i>	41	51	48	-	-	-
Commodity contracts - natural gas <i>(billions of cubic feet)</i>	(45)	(174)	(79)	(18)	3	1
Commodity contracts - crude oil <i>(millions of barrels)</i>	(4)	(12)	(18)	(9)	-	-
Commodity contracts - NGL <i>(millions of barrels)</i>	(5)	(8)	-	-	-	-
Commodity contracts - power <i>(megawatt hours (MWH))</i>	32	40	40	30	31	(23)

December 31, 2014	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase (millions of United States dollars)	240	25	413	2	2	2
Foreign exchange contracts - United States dollar forwards - sell (millions of United States dollars)	3,203	2,470	2,832	3,100	2,441	2,901
Foreign exchange contracts - Euro forwards - purchase (millions of Euros)	15	-	-	-	-	-
Interest rate contracts - short-term borrowings (millions of Canadian dollars)	5,767	5,486	4,851	3,529	222	469
Interest rate contracts - long-term debt (millions of Canadian dollars)	3,528	1,762	2,470	1,176	-	-
Equity contracts (millions of Canadian dollars)	41	51	-	-	-	-
Commodity contracts - natural gas (billions of cubic feet)	(62)	(10)	(25)	(1)	-	-
Commodity contracts - crude oil (millions of barrels)	3	(18)	(18)	(9)	-	-
Commodity contracts - NGL (millions of barrels)	(5)	-	-	-	-	-
Commodity contracts - power (MWH)	25	40	40	30	31	-

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

	Three months ended		Nine months ended	
	September 30, 2015	2014	September 30, 2015	2014
<i>(millions of Canadian dollars)</i>				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	36	22	66	(9)
Interest rate contracts	(390)	(173)	(662)	(694)
Commodity contracts	18	9	8	(8)
Other contracts	(26)	7	(40)	15
Net investment hedges				
Foreign exchange contracts	(105)	(63)	(206)	(66)
	(467)	(198)	(834)	(762)
Amount of gains/(loss) reclassified from AOCI to earnings				
<i>(effective portion)</i>				
Foreign exchange contracts ¹	-	(5)	6	10
Interest rate contracts ²	20	30	53	74
Commodity contracts ³	(13)	2	(35)	14
Other contracts ⁴	16	(5)	22	(12)
	23	22	46	86
De-designation of qualifying hedges in connection with the Canadian Restructuring Plan (Note 2)				
Interest rate contracts ^{2,5}	338	-	338	-
	338	-	338	-
Amount of gains/(loss) reclassified from AOCI to earnings				
<i>(ineffective portion and amount excluded from effectiveness testing)</i>				
Interest rate contracts ²	25	130	(10)	158
Commodity contracts ³	-	-	5	3
	25	130	(5)	161

¹ Reported within Transportation and other services revenues and Other expense in the Consolidated Statements of Earnings.

² Reported within Interest expense in the Consolidated Statement of Earnings.

³ Reported within Transportation and other services revenues, Commodity revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

⁴ Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

⁵ The amounts above include \$338 million in the three and nine months ended September 30, 2015 relating to the de-designation of qualifying hedges in connection with the Canadian Restructuring Plan.

The Company estimates that \$92 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 51 months at September 30, 2015.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
<i>(millions of Canadian dollars)</i>				
Foreign exchange contracts ¹	(1,087)	(568)	(1,992)	(510)
Interest rate contracts ^{2,5}	(380)	1	(380)	3
Commodity contracts ³	204	146	(23)	447
Other contracts ⁴	(16)	5	(15)	12
Total unrealized derivative fair value gains/(loss)	(1,279)	(416)	(2,410)	(48)

1 Reported within Transportation and other services revenues (2015 - \$1,253 million loss; 2014 - \$254 million loss) and Other expense (2015 - \$739 million loss; 2014 - \$256 million loss) in the Consolidated Statements of Earnings.

2 Reported as an (increase)/decrease to Interest expense in the Consolidated Statements of Earnings.

3 Reported within Transportation and other services revenues (2015 - \$148 million gain; 2014 - \$395 million gain), Commodity sales revenues (2015 - \$326 million loss; 2014 - nil), Commodity costs (2015 - \$162 million gain; 2014 - \$57 million gain) and Operating and administrative expense (2015 - \$7 million loss; 2014 - \$5 million loss) in the Consolidated Statements of Earnings.

4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

5 The amounts above include \$338 million in the three and nine months ended September 30, 2015 relating to the designation of qualifying hedges in connection with the Canadian Restructuring Plan (Note 2).

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. The Company, through committed credit facilities with a diversified group of banks and institutions, targets to maintain sufficient liquidity to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at September 30, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, the Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	September 30, 2015	December 31, 2014
<i>(millions of Canadian dollars)</i>		
Canadian financial institutions	45	58
United States financial institutions	308	240
European financial institutions	29	73
Other ¹	331	310
	713	681

¹ Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at September 30, 2015, the Company had provided letters of credit totalling \$559 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held \$22 million of cash collateral on derivative asset exposures as at September 30, 2015 and \$33 million of cash collateral at December 31, 2014.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates, and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Gas Distribution, credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company's held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

September 30, 2015	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
<i>(millions of Canadian dollars)</i>				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	10	-	10
Commodity contracts	14	110	465	589
Other contracts	-	3	-	3
	14	123	465	602
Long-term derivative assets				
Foreign exchange contracts	-	107	-	107
Interest rate contracts	-	1	-	1
Commodity contracts	-	35	145	180
	-	143	145	288
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(714)	-	(714)
Interest rate contracts	-	(659)	-	(659)
Commodity contracts	(8)	(97)	(360)	(465)
Other contracts	-	(2)	-	(2)
	(8)	(1,472)	(360)	(1,840)
Long-term derivative liabilities				
Foreign exchange contracts	-	(2,962)	-	(2,962)
Interest rate contracts	-	(992)	-	(992)
Commodity contracts	-	(44)	(227)	(271)
Other contracts	-	(14)	-	(14)
	-	(4,012)	(227)	(4,239)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(3,559)	-	(3,559)
Interest rate contracts	-	(1,650)	-	(1,650)
Commodity contracts	6	4	23	33
Other contracts	-	(13)	-	(13)
	6	(5,218)	23	(5,189)

December 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
<i>(millions of Canadian dollars)</i>				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	13	-	13
Interest rate contracts	-	8	-	8
Commodity contracts	62	140	333	535
Other contracts	-	12	-	12
	62	173	333	568
Long-term derivative assets				
Foreign exchange contracts	-	51	-	51
Interest rate contracts	-	5	-	5
Commodity contracts	-	22	113	135
Other contracts	-	8	-	8
	-	86	113	199
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(301)	-	(301)
Interest rate contracts	-	(438)	-	(438)
Commodity contracts	(28)	(137)	(116)	(281)
	(28)	(876)	(116)	(1,020)
Long-term derivative liabilities				
Foreign exchange contracts	-	(1,196)	-	(1,196)
Interest rate contracts	-	(576)	-	(576)
Commodity contracts	-	(125)	(181)	(306)
	-	(1,897)	(181)	(2,078)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(1,433)	-	(1,433)
Interest rate contracts	-	(1,001)	-	(1,001)
Commodity contracts	34	(100)	149	83
Other contracts	-	20	-	20
	34	(2,514)	149	(2,331)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

September 30, 2015	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
<i>(fair value in millions of Canadian dollars)</i>						
Commodity contracts - financial¹						
Natural gas	2	Forward gas price	3.20	4.43	3.76	\$/mmbtu ³
Crude	(2)	Forward crude price	41.87	62.75	59.35	\$/barrel
NGL	14	Forward NGL price	0.27	1.32	0.96	\$/gallon
Power	(153)	Forward power price	34.00	75.22	53.12	\$/MWH
Commodity contracts - physical¹						
Natural gas	(7)	Forward gas price	2.75	4.72	3.48	\$/mmbtu ³
Crude	32	Forward crude price	36.05	127.69	59.40	\$/barrel
NGL	12	Forward NGL price	0.22	1.86	0.79	\$/gallon
Commodity options²						
Crude	46	Option volatility	23%	36%	29%	
NGL	79	Option volatility	19%	63%	46%	

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¹ Financial and physical forward commodity contracts are valued using a market approach valuation technique.

² Commodity options contracts are valued using an option model valuation technique.

³ One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of the Company's Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices and, for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for the Company's Level 3 derivatives. Changes in price volatility would change the value of

the option contracts. Generally speaking, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

	Nine months ended September 30,	
	2015	2014
<i>(millions of Canadian dollars)</i>		
Level 3 net derivative asset/(liability) at beginning of period	149	(164)
Total gains/(loss)		
Included in earnings ¹	43	29
Included in OCI	(17)	4
Settlements	(152)	11
Level 3 net derivative liability at end of period	23	(120)

¹ Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

The Company's policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at September 30, 2015 or 2014.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled \$124 million at September 30, 2015 (December 31, 2014 - \$99 million).

The Company has restricted investments held in trust totalling \$34 million as at September 30, 2015 (December 31, 2014 - nil).

The Company has a held to maturity preferred share investment carried at its amortized cost of \$335 million as at September 30, 2015 (December 31, 2014 - \$323 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. As at September 30, 2015, the fair value of this preferred share investment approximates its face value of \$580 million (December 31, 2014 - \$580 million).

As at September 30, 2015, the Company's long-term debt had a carrying value of \$39,694 million (December 31, 2014 - \$34,427 million) and a fair value of \$40,602 million (December 31, 2014 - \$36,637 million).

NET INVESTMENT HEDGES

The Company has designated a portion of its United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of its net investment in United States dollar denominated investments and subsidiaries.

During the nine months ended September 30, 2015, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of \$536 million (2014 - unrealized loss of \$97 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of \$203 million (2014 - unrealized loss of \$66 million) in OCI. The Company also recognized a realized loss of \$20 million (2014 - realized gain of \$8 million) in OCI associated with the settlement of foreign exchange forward contracts and designated debt that had matured during the period. There was no ineffectiveness during the nine months ended September 30, 2015 (2014 - nil).

13. INCOME TAXES

The effective income tax rates for the three and nine months ended September 30, 2015 were an expense of 21.2% and 16.6%, respectively (2014 - 47.7% recovery and 22.5% expense, respectively). The period-over-period change in the effective tax rate is primarily attributable to the effects of rate-regulated accounting and other permanent items relative to the loss in the first nine months of 2015 as compared with the corresponding 2014 period, offset by a \$39 million tax expense arising from an intercompany transfer of assets during the second quarter of 2015 and an \$88 million write-off of a regulatory asset during the third quarter of 2015 as a result of a common control transaction. The effective income tax rate for the nine months ended September 30, 2015 was further impacted by an out-of-period adjustment recorded in the first quarter of 2015 (Note 4) and a \$272 million valuation allowance on deferred tax assets on certain United States investments.

14. RETIREMENT AND POSTRETIREMENT BENEFITS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides OPEB, which primarily include supplemental health and dental, health spending account and life insurance coverage, for qualifying retired employees.

NET BENEFIT COSTS RECOGNIZED

	Three months ended		Nine months ended	
	September 30,	September 30,	September 30,	September 30,
	2015	2014	2015	2014
<i>(millions of Canadian dollars)</i>				
Benefits earned during the period	43	29	131	88
Interest cost on projected benefit obligations	27	25	80	77
Expected return on plan assets	(36)	(32)	(109)	(96)
Amortization of prior service costs	-	-	1	1
Amortization of actuarial loss	12	7	36	21
Net benefit costs on an accrual basis ^{1,2}	46	29	139	91

¹ Included in net benefit costs for the three and nine months ended September 30, 2015 are costs related to OPEB of \$3 million and \$10 million, respectively (2014 - \$3 million and \$11 million, respectively).

² For the three and nine months ended September 30, 2015, offsetting regulatory liabilities of nil (2014 - \$2 million and \$5 million regulatory liabilities, respectively) have been recorded to the extent pension and OPEB costs are expected to be refunded to, or collected from, customers in future rates.

15. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 35.8% combined direct and indirect economic interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) (the Order) which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged the completion of the Order. In November of 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). The MDEQ has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, EEP reached a settlement with the MDEQ and the Michigan Attorney General's offices regarding the Line 6B crude oil release. As stipulated in the settlement, EEP agreed to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity; (2) pay US\$5 million as mitigation for impacts to the banks, bottomlands and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the river; (3) continue to reimburse the State of Michigan for costs arising from oversight of EEP activities since the release; and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan.

As at September 30, 2015, EEP's cumulative cost estimate for the Line 6B crude oil release remains at US\$1.2 billion (\$193 million after-tax attributable to Enbridge).

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2015. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois, caused by a third party water pipeline failure which damaged EEP's pipeline. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release. On February 20, 2015, Enbridge, EEP and their affiliates agreed to a consent order releasing the parties from any claims, liability or penalties.

Insurance

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, the insurance program is renewed and includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US\$650 million for pollution liability for Enbridge and its affiliates. Including EEP's remediation spending through September 30, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at September 30, 2015, EEP has recorded total insurance recoveries of US\$547 million (\$80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US\$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurer who is disputing recovery eligibility for Line 6B costs. In March 2015, Enbridge reached an agreement with that insurer to submit the claim to binding arbitration which is not scheduled to occur until the fourth quarter of 2016. While the Company believes that those costs are eligible for recovery, there can be no assurance that it will prevail in the arbitration.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2016 with a liability program aggregate limit of US\$860 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately five actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material to the Company's results of operations or financial condition.

As at September 30, 2015, included in EEP's estimated costs related to the Line 6B crude oil release is US\$48 million in fines and penalties. Of this amount, US\$40 million related to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US\$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. EEP has entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties and injunctive relief are ongoing.

In June 2015, EEP reached a separate agreement with the United States of America (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians and the Nottawaseppi Huron Band of the Potawatomi Indians to pay approximately US\$3.9 million that EEP had accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.