ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2014

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and independent auditors have unrestricted access to the AF&RC.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and to provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2014, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2014.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company and its internal control over financial reporting in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

"signed"

Al Monaco
President & Chief Executive Officer

"signed"

John K. Whelen
Executive Vice President &
Chief Financial Officer

February 19, 2015

Independent Auditor’s Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.’s 2014, 2013 and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management’s responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2014 and December 31, 2013 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014 in accordance with accounting principles generally accepted in the United States of America.

Report on internal control over financial reporting

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

Auditor's responsibility

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion

In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

February 19, 2015

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2014	2013	2012
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**28,281**	26,039	18,494
Gas distribution sales	**2,853**	2,265	1,910
Transportation and other services	**6,507**	4,614	4,256
	37,641	32,918	24,660
Expenses			
Commodity costs	**27,504**	25,222	17,959
Gas distribution costs	**1,979**	1,585	1,220
Operating and administrative	**3,281**	3,014	2,739
Depreciation and amortization	**1,577**	1,370	1,236
Environmental costs, net of recoveries	**100**	362	(88)
	34,441	31,553	23,066
	3,200	1,365	1,594
Income from equity investments *(Note 11)*	**368**	330	195
Other income/(expense) *(Note 26)*	**(266)**	(135)	238
Interest expense *(Note 16)*	**(1,129)**	(947)	(841)
	2,173	613	1,186
Income taxes *(Note 24)*	**(611)**	(123)	(171)
Earnings from continuing operations	**1,562**	490	1,015
Discontinued operations *(Note 9)*			
Earnings/(loss) from discontinued operations before income taxes	**73**	6	(123)
Income taxes (expense)/recovery from discontinued operations	**(27)**	(2)	44
Earnings/(loss) from discontinued operations	**46**	4	(79)
Earnings	**1,608**	494	936
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(203)**	135	(229)
Earnings attributable to Enbridge Inc.	**1,405**	629	707
Preference share dividends	**(251)**	(183)	(105)
Earnings attributable to Enbridge Inc. common shareholders	**1,154**	446	602
Earnings attributable to Enbridge Inc. common shareholders			
Earnings from continuing operations	**1,108**	442	681
Earnings/(loss) from discontinued operations, net of tax	**46**	4	(79)
	1,154	446	602
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**1.34**	0.55	0.88
Discontinued operations	**0.05**	-	(0.10)
	1.39	0.55	0.78
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**1.32**	0.55	0.87
Discontinued operations	**0.05**	-	(0.10)
	1.37	0.55	0.77

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings	**1,608**	494	936
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(833)**	697	(176)
Change in unrealized gains/(loss) on net investment hedges	**(270)**	(96)	13
Other comprehensive income from equity investees	**10**	11	2
Reclassification to earnings of realized cash flow hedges	**76**	72	7
Reclassification to earnings of unrealized cash flow hedges	**158**	39	20
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	**15**	27	18
Actuarial gains/(loss) on pension plans and other postretirement benefits	**(191)**	114	(56)
Change in foreign currency translation adjustment	**1,238**	710	(158)
Other comprehensive income/(loss)	**203**	1,574	(330)
Comprehensive income	**1,811**	2,068	606
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(242)**	(276)	(165)
Comprehensive income attributable to Enbridge Inc.	**1,569**	1,792	441
Preference share dividends	**(251)**	(183)	(105)
Comprehensive income attributable to Enbridge Inc. common shareholders	**1,318**	1,609	336

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**5,141**	3,707	1,056
Preference shares issued	**1,374**	1,434	2,651
Balance at end of year	**6,515**	5,141	3,707
Common shares *(Note 20)*			
Balance at beginning of year	**5,744**	4,732	3,969
Common shares issued	**446**	582	388
Dividend reinvestment and share purchase plan	**428**	361	297
Shares issued on exercise of stock options	**51**	69	78
Balance at end of year	**6,669**	5,744	4,732
Additional paid-in capital			
Balance at beginning of year	**746**	522	242
Stock-based compensation	**31**	28	26
Options exercised	**(14)**	(17)	(17)
Issuance of treasury stock *(Note 11)*	**22**	208	236
Enbridge Energy Partners, L.P. equity restructuring *(Note 19)*	**1,601**	-	-
Transfer of interest to Enbridge Income Fund	**176**	-	-
Drop down of interest to Midcoast Energy Partners, L.P.	**(18)**	-	-
Dilution gains and other	**5**	5	35
Balance at end of year	**2,549**	746	522
Retained earnings			
Balance at beginning of year	**2,550**	3,173	3,643
Earnings attributable to Enbridge Inc.	**1,405**	629	707
Preference share dividends	**(251)**	(183)	(105)
Common share dividends declared	**(1,177)**	(1,035)	(895)
Dividends paid to reciprocal shareholder	**17**	19	20
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 19)*	**(973)**	(53)	(197)
Balance at end of year	**1,571**	2,550	3,173
Accumulated other comprehensive loss *(Note 22)*			
Balance at beginning of year	**(599)**	(1,762)	(1,496)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**164**	1,163	(266)
Balance at end of year	**(435)**	(599)	(1,762)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(86)**	(126)	(187)
Issuance of treasury stock	**3**	40	61
Balance at end of year	**(83)**	(86)	(126)
Total Enbridge Inc. shareholders' equity	**16,786**	13,496	10,246
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**4,014**	3,258	3,141
Earnings/(loss) attributable to noncontrolling interests	**214**	(111)	241
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(192)**	166	(39)
Change in foreign currency translation adjustment	**146**	223	(60)
Reclassification to earnings of realized cash flow hedges	**18**	4	23
Reclassification to earnings of unrealized cash flow hedges	**77**	14	13
	49	407	(63)
Comprehensive income attributable to noncontrolling interests	**263**	296	178
Distributions *(Note 19)*	**(535)**	(468)	(421)
Contributions *(Note 19)*	**212**	922	382
Dilution gains	**-**	-	6
Acquisitions *(Note 6)*	**351**	-	(25)
Enbridge Energy Partners, L.P. equity restructuring *(Note 19)*	**(2,330)**	-	-
Drop down of interest to Midcoast Energy Partners, L.P. *(Note 19)*	**39**	-	-
Other	**1**	6	(3)
Balance at end of year	**2,015**	4,014	3,258
Total equity	**18,801**	17,510	13,504
Dividends paid per common share	**1.40**	1.26	1.13

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Operating activities			
Earnings	**1,608**	494	936
(Earnings)/loss from discontinued operations	**(46)**	(4)	79
Depreciation and amortization	**1,577**	1,370	1,236
Deferred income taxes *(Note 24)*	**587**	131	3
Changes in unrealized (gains)/loss on derivative instruments, net	**(96)**	1,262	665
Cash distributions in excess of equity earnings	**196**	355	439
Impairment	**18**	6	39
Gain on disposition *(Note 6)*	**(38)**	(18)	-
Hedge ineffectiveness *(Note 23)*	**210**	48	20
Inventory revaluation allowance *(Note 8)*	**174**	4	10
Other	**115**	(43)	79
Changes in regulatory assets and liabilities	**22**	(11)	44
Changes in environmental liabilities, net of recoveries	**(78)**	148	(26)
Changes in operating assets and liabilities *(Note 27)*	**(1,721)**	(409)	(660)
Cash provided by continuing operations	**2,528**	3,333	2,864
Cash provided by discontinued operations *(Note 9)*	**19**	8	10
	2,547	3,341	2,874
Investing activities			
Additions to property, plant and equipment	**(10,524)**	(8,235)	(5,194)
Long-term investments	**(854)**	(1,018)	(531)
Additions to intangible assets	**(208)**	(212)	(163)
Acquisitions*)*	**(394)**	-	(340)
Proceeds from disposition	**85**	41	18
Affiliate loans, net	**13**	8	8
Changes in restricted cash	**(13)**	(15)	(2)
Cash used in continuing operations	**(11,895)**	(9,431)	(6,204)
Cash provided by discontinued operations *(Note 9)*	**4**	-	-
	(11,891)	(9,431)	(6,204)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**734**	(350)	412
Net change in commercial paper and credit facility draws	**4,212**	1,562	(294)
Southern Lights project financing repayments	**(1,519)**	(5)	(13)
Debenture and term note issues - Southern Lights	**1,507**	-	-
Debenture and term note issues	**5,414**	2,845	2,199
Debenture and term note repayments	**(1,348)**	(660)	(349)
Repayment of acquired debt	**-**	-	(160)
Contributions from noncontrolling interests	**212**	922	448
Distributions to noncontrolling interests	**(535)**	(468)	(421)
Contributions from redeemable noncontrolling interests	**323**	92	213
Distributions to redeemable noncontrolling interests	**(79)**	(72)	(49)
Preference shares issued	**1,365**	1,428	2,634
Common shares issued	**478**	628	465
Preference share dividends	**(245)**	(178)	(93)
Common share dividends	**(749)**	(674)	(597)
	9,770	5,070	4,395
Effect of translation of foreign denominated cash and cash equivalents	**59**	20	(12)
Increase/(decrease) in cash and cash equivalents	**485**	(1,000)	1,053
Cash and cash equivalents at beginning of year - continuing operations	**756**	1,776	723
Cash and cash equivalents at beginning of year - discontinued operations	**20**	-	-
Cash and cash equivalents at end of year	**1,261**	776	1,776
Cash and cash equivalents - discontinued operations	**-**	(20)	-
Cash and cash equivalents - continuing operations	**1,261**	756	1,776
Supplementary cash flow information			
Income taxes paid	**9**	107	267
Interest paid	**1,435**	1,097	988

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2014**	2013
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,261**	756
Restricted cash	**47**	34
Accounts receivable and other *(Note 7)*	**5,504**	4,956
Accounts receivable from affiliates	**241**	65
Inventory *(Note 8)*	**1,148**	1,115
Assets held for sale *(Note 9)*	**-**	24
	8,201	6,950
Property, plant and equipment, net *(Note 9)*	**53,830**	42,279
Long-term investments *(Note 11)*	**5,408**	4,212
Deferred amounts and other assets *(Note 12)*	**3,208**	2,662
Intangible assets, net *(Note 13)*	**1,166**	1,004
Goodwill *(Note 14)*	**483**	445
Deferred income taxes *(Note 24)*	**561**	16
	72,857	57,568
Liabilities and equity		
Current liabilities		
Bank indebtedness	**507**	338
Short-term borrowings *(Note 16)*	**1,041**	374
Accounts payable and other *(Note 15)*	**6,444**	6,664
Accounts payable to affiliates	**80**	46
Interest payable	**264**	228
Environmental liabilities	**161**	260
Current maturities of long-term debt *(Note 16)*	**1,004**	2,811
Liabilities held for sale *(Note 9)*	**-**	7
	9,501	10,728
Long-term debt *(Note 16)*	**33,423**	22,357
Other long-term liabilities *(Note 17)*	**4,041**	2,938
Deferred income taxes *(Note 24)*	**4,842**	2,925
Liabilities held for sale *(Note 9)*	**-**	57
	51,807	39,005
Commitments and contingencies *(Note 29)*		
Redeemable noncontrolling interests *(Note 19)*	**2,249**	1,053
Equity		
Share capital *(Note 20)*		
Preference shares	**6,515**	5,141
Common shares (852 and 831 outstanding at December 31, 2014 and 2013, respectively)	**6,669**	5,744
Additional paid-in capital	**2,549**	746
Retained earnings	**1,571**	2,550
Accumulated other comprehensive loss *(Note 22)*	**(435)**	(599)
Reciprocal shareholding *(Note 11)*	**(83)**	(86)
Total Enbridge Inc. shareholders' equity	**16,786**	13,496
Noncontrolling interests *(Note 19)*	**2,015**	4,014
	18,801	17,510
	72,857	57,568

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

Approved by the Board of Directors:

"signed"
David A. Arledge
Chair

"signed"
J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists 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 (Seaway Pipeline) and Flanagan South Pipeline, Southern Lights Pipeline, Spearhead Pipeline and Feeder Pipelines and Other.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, gathering and processing facilities and the Company's energy services businesses, along with renewable energy and transmission facilities.

Investments in natural gas pipelines include the Company's interests in the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance Pipeline and Canadian Midstream assets located in northeast British Columbia and northwest Alberta. The energy services businesses undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on Alliance Pipeline, Vector and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 33.7% (2013 - 20.6%) 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 66.4% (2013 - 67.3%) economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). 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.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines, including the Lakehead Pipeline System (Lakehead System), which is the United States portion of the Enbridge mainline system, and transports, gathers, processes and markets natural gas and NGL. The primary operations of the Fund include renewable power generation, crude oil and liquids pipeline, including interests in Southern Lights Pipeline, and storage businesses in western Canada and a 50% interest in the Alliance Pipeline.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, general corporate investments and financing costs not allocated to the business segments.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities and Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; fair value of asset retirement obligations (ARO) *(Note 18)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Note 23)*; provisions for income taxes *(Note 24)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 25)*; commitments and contingencies *(Note 29)*; and estimates of losses related to environmental remediation obligations *(Note 29)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and variable interest entities for which the Company is the primary beneficiary. Upon inception of a contractual agreement, the Company performs an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a variable interest entity (VIE). Where the Company concludes it is the primary beneficiary of a VIE, the Company will consolidate the accounts of that entity. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where the Company retains an undivided interest in assets and liabilities, Enbridge records its proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which the Company exercises significant influence are accounted for using the equity method.

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator’s actions differ from the Company’s expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 5)*.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator’s actions differ from the Company’s expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. The Company recognizes revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require the Company to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay the Company a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. From July 1, 2011 onward, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, the Company prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenues are recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area.

For natural gas and marketing businesses, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges at December 31, 2014, 2013 or 2012.

Net Investment Hedges
Gains and losses arising from translation of net investment in foreign operations from their functional currencies to the Company's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA). The Company designates foreign currency derivatives and United States dollar denominated debt as hedges of net investments in United States dollar denominated foreign operations. As a result, the effective portion of the change in the fair value of the foreign currency derivatives as well as the translation of United States dollar denominated debt are reflected in OCI and any ineffectiveness is reflected in current period earnings. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from disposal of a foreign operation.

Classification of Derivatives
The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs as Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS
Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, the Company capitalizes interest costs associated with its investment during such period.

OTHER INVESTMENTS
Generally, the Company classifies equity investments in entities over which it does not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are classified as available for sale investments measured at fair value through OCI. Dividends received from investments carried at cost are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity not owned by the Company in such entities is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund's noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar presentation currency are included in the cumulative translation adjustment component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES
Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

ALLOWANCE FOR DOUBTFUL ACCOUNTS
Allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY
Inventory is comprised of natural gas in storage held in EGD and crude oil and natural gas held primarily by energy services businesses in the Gas Pipelines, Processing and Energy Services and Sponsored Investments segments. Natural gas in storage in EGD is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs on the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt and are recorded in Interest expense.

INTANGIBLE ASSETS
Intangible assets consist primarily of acquired long-term transportation or power purchase agreements, natural gas supply opportunities and certain software costs. Natural gas supply opportunities are growth opportunities, identified upon acquisition, present in gas producing zones where certain of EEP's gas systems are located. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Company's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

IMPAIRMENT
The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality tables were issued by the Society of Actuaries in the United States. These new tables, along with the Canadian Institute of Actuaries tables that were revised in 2013, were used by the Company for measurement of its December 31, 2014 benefit obligations of its United States pension plan (the United States Plan) and the Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans), respectively. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates for its Canadian Plans, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets, Accounts payable and other or Other long-term liabilities, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

Certain regulated utility operations of the Company expect to recover pension expense in future rates and therefore record a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to EGD's OPEB obligation was not recorded given recovery in rates was not probable. Commencing in 2012, pursuant to a specific rate order allowing EGD to recover OPEB costs determined on an accrual basis in rates, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance based stock options (PBSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PBSO granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period with a corresponding credit to Additional paid-in capital. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSU vest at the completion of a three-year term and RSU vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSU is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

The Company expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. The Company expenses costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. The Company records liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. The Company's estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. The Company evaluates recoveries from insurance coverage separately from the liability and, when recovery is probable, the Company records and reports an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent's Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the consolidated financial statements as a result of adopting this update.

Pushdown Accounting for Business Combinations

Effective November 18, 2014, the Company prospectively adopted ASU 2014-17 which provides an acquired entity with the option to apply pushdown accounting in its separate financial statements upon the occurrence of a change-in-control event. There was no impact to the consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items

ASU 2015-01 was issued in January 2015 and 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 income statement. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Hybrid Financial Instruments Issued in the Form of a Share

ASU 2014-16 was issued in November 2014 with the intent to eliminate the use of different methods in practice in the accounting for hybrid financial instruments issued in the form of a share. The new standard clarifies the evaluation of the economic characteristics and risks of a host contract in these hybrid financial instruments. The Company is currently assessing the impact of the new standard on its consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2015 and is to be applied on a modified retrospective basis.

Development Stage Entities

ASU 2014-10, issued in June 2014, eliminates the concept of a development stage entity from U.S. GAAP and removes the related incremental reporting requirements. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and is not expected to have a material impact on the Company's consolidated financial statements. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. The Company is currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

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. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

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

ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

4. SEGMENTED INFORMATION

Year ended December 31, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services[2]	Sponsored Investments[2]	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**2,283**	**3,216**	**23,023**	**9,119**	**-**	**37,641**
Commodity and gas distribution costs	**-**	**(1,979)**	**(21,921)**	**(5,583)**	**-**	**(29,483)**
Operating and administrative	**(1,101)**	**(530)**	**(175)**	**(1,438)**	**(37)**	**(3,281)**
Depreciation and amortization	**(498)**	**(304)**	**(114)**	**(642)**	**(19)**	**(1,577)**
Environmental costs, net of recoveries	**7**	**-**	**-**	**(107)**	**-**	**(100)**
	691	**403**	**813**	**1,349**	**(56)**	**3,200**
Income/(loss) from equity investments	**160**	**-**	**136**	**86**	**(14)**	**368**
Other income/(expense)	**12**	**(8)**	**38**	**5**	**(313)**	**(266)**
Interest income/(expense)	**(372)**	**(165)**	**(98)**	**(559)**	**65**	**(1,129)**
Income taxes recovery/(expense)	**(24)**	**(17)**	**(318)**	**(263)**	**11**	**(611)**
Earnings/(loss) from continuing operations	**467**	**213**	**571**	**618**	**(307)**	**1,562**
Discontinued operations						
Earnings from discontinued operations before income taxes	**-**	**-**	**73**	**-**	**-**	**73**
Income taxes from discontinued operations	**-**	**-**	**(27)**	**-**	**-**	**(27)**
Earnings from discontinued operations	**-**	**-**	**46**	**-**	**-**	**46**
Earnings/(loss)	**467**	**213**	**617**	**618**	**(307)**	**1,608**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(4)**	**-**	**-**	**(199)**	**-**	**(203)**
Preference share dividends	**-**	**-**	**-**	**-**	**(251)**	**(251)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**463**	**213**	**617**	**419**	**(558)**	**1,154**
Additions to property, plant and equipment[5]	**5,917**	**603**	**678**	**3,269**	**60**	**10,527**
Total assets	**27,657**	**9,320**	**7,601**	**23,515**	**4,764**	**72,857**

Year ended December 31, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services[2]	Sponsored Investments[2]	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	2,272	2,741	20,310	7,595	-	32,918
Commodity and gas distribution costs	-	(1,585)	(20,244)	(4,978)	-	(26,807)
Operating and administrative	(1,006)	(534)	(221)	(1,226)	(27)	(3,014)
Depreciation and amortization	(429)	(321)	(75)	(530)	(15)	(1,370)
Environmental costs, net of recoveries	(79)	-	-	(283)	-	(362)
	758	301	(230)	578	(42)	1,365
Income from equity investments	118	-	154	56	2	330
Other income/(expense)	39	20	39	37	(270)	(135)
Interest income/(expense)	(319)	(160)	(81)	(409)	22	(947)
Income taxes recovery/(expense)	(165)	(32)	50	(133)	157	(123)
Earnings/(loss) from continuing operations	431	129	(68)	129	(131)	490
Discontinued operations						
Earnings from discontinued operations before income taxes	-	-	6	-	-	6
Income taxes from discontinued operations	-	-	(2)	-	-	(2)
Earnings from discontinued operations	-	-	4	-	-	4
Earnings/(loss)	431	129	(64)	129	(131)	494
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	-	139	-	135
Preference share dividends	-	-	-	-	(183)	(183)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	427	129	(64)	268	(314)	446
Additions to property, plant and equipment[5]	4,360	533	744	2,565	34	8,236
Total assets	20,950	7,942	7,015	18,527	3,134	57,568

Year ended December 31, 2012	Liquids Pipelines[3]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3,4]	Sponsored Investments[2,3]	Corporate[1,4]	Consolidated
(millions of Canadian dollars)						
Revenues	2,445	2,438	13,106	6,671	-	24,660
Commodity and gas distribution costs	-	(1,220)	(13,676)	(4,283)	-	(19,179)
Operating and administrative	(942)	(528)	(142)	(1,076)	(51)	(2,739)
Depreciation and amortization	(399)	(336)	(57)	(431)	(13)	(1,236)
Environmental costs, net of recoveries	-	-	-	88	-	88
	1,104	354	(769)	969	(64)	1,594
Income/(loss) from equity investments	46	-	141	55	(47)	195
Other income/(expense)	(7)	83	33	49	80	238
Interest income/(expense)	(250)	(164)	(50)	(397)	20	(841)
Income taxes recovery/(expense)	(192)	(66)	269	(169)	(13)	(171)
Earnings/(loss) from continuing operations	701	207	(376)	507	(24)	1,015
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(123)	-	-	(123)
Income taxes recovery from discontinued operations	-	-	44	-	-	44
Loss from discontinued operations	-	-	(79)	-	-	(79)
Earnings/(loss)	701	207	(455)	507	(24)	936
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	(1)	(224)	-	(229)
Preference share dividends	-	-	-	-	(105)	(105)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	697	207	(456)	283	(129)	602
Additions to property, plant and equipment[5]	1,927	445	933	1,886	4	5,195

1 *Included within the Corporate segment was Interest income of $694 million (2013 - $443 million; 2012 - $336 million) charged to other operating segments.*

2 *In November 2014, Enbridge's 50% interest in the United States portion of Alliance Pipeline (Alliance Pipeline US) was transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $41 million (2013 - $43 million; 2012 - $39 million) have not been reclassified between segments for presentation purposes.*

3 *In December 2012, certain crude oil storage and renewable energy assets were transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $33 million have not been reclassified among*

segments for presentation purposes.

4 *Due to a change in organizational structure effective January 1, 2013, for the year ended December 31, 2012 earnings of $1 million and additions to property, plant and equipment of $108 million were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.*

5 *Includes allowance for equity funds used during construction.*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Canada	**14,963**	12,690	11,629
United States	**22,678**	20,228	13,031
	37,641	32,918	24,660

1 *Revenues are based on the country of origin of the product or service sold.*

Property, Plant and Equipment

December 31,	**2014**	2013
(millions of Canadian dollars)		
Canada	**27,420**	22,865
United States	**26,410**	19,414
	53,830	42,279

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation. The Company's significant regulated businesses and related accounting impacts are described below.

Canadian Mainline

Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on the Lakehead System and delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with NEB guidelines, was approved by the NEB in June 2011 and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a NEB rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The United States portion of the Southern Lights Pipeline (Southern Lights US) is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline (Southern Lights Canada) is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. For the year ended December 31, 2014, rates were set under the customized incentive rate plan (the IR Plan) approved by the OEB, with modifications, for 2014 through 2018, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE.

The OEB approved final 2014 rates to be implemented with an effective date of January 1, 2014. Within annual rate proceedings for 2015 through 2018, the IR Plan requires allowed revenues, and corresponding rates, to be updated annually for select items. The OEB also approved the adoption of a new approach for determining net salvage percentages to be included within EGD's approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves. The IR Plan includes an earnings sharing mechanism, whereby any return over the allowed rate of return for a given year under the IR Plan will be shared equally with customers.

For the year ended December 31, 2013, rates were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed ROE. The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories. The earnings sharing mechanism, which was previously in effect under revenue cap incentive regulation (IR), did not apply to the 2013 Settlement.

The 2013 Settlement allowed EGD to recognize revenue and a corresponding regulatory asset relating to OPEB as it established the right to recover previous OPEB costs of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The gain was presented within Other income/(expense) on the Consolidated Statements of Earnings for the year ended December 31, 2012 *(Note 26)*. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

Prior to 2013, EGD operated under an IR mechanism, calculated on a revenue per customer basis, with the OEB for a five-year period between 2008 and 2012. Under the IR mechanism, the Company was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

EGD's after-tax rate of return on common equity embedded in rates was 9.4% for the year ended December 31, 2014 (2013 - 8.9%) based on a 36% (2013 - 36%) deemed common equity component of capital for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick is regulated by the EUB and currently sets tolls at the lower of market-based or cost of service rates.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	**907**	727
Tolling deferrals[2]	**(39)**	(36)
Recoverable income taxes[3]	**46**	42
Gas Distribution		
Deferred income taxes[4]	**275**	214
Purchased gas variance[5]	**673**	-
Pension plans and OPEB[6]	**171**	94
Constant dollar net salvage adjustment[7]	**37**	-
Future removal and site restoration reserves[8]	**(562)**	(929)
Site restoration[9]	**(283)**	-
Revenue adjustment[10]	**(52)**	-
Transaction services deferral[11]	**(26)**	(51)
Sponsored Investments		
Deferred income taxes[1]	**15**	28
Transportation revenue adjustments[12]	**36**	33

1 *The asset represents the regulatory offset to deferred income tax liabilities that are expected to be recovered under flow-through income tax treatment. The recovery period depends on future reversal of temporary differences.*

2 *The liability reflects net tax benefits expected to be refunded through future transportation tolls on Southern Lights Canada. The balance is expected to accumulate for approximately eight years before being refunded through tolls.*

3 *The asset represents future revenues to be collected from shippers for Southern Lights US to recover federal income taxes payable on the equity component of AFUDC. The recovery period is approximately 30 years.*

4 *The asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred income taxes are expected to be recovered or refunded through regulator-approved rates. The recovery period depends on future temporary differences. Deferred income taxes in Gas Distribution are excluded from the rate base and do not earn an ROE.*

5 *The purchased gas variance (PGVA) balance represents the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016.*

6 *The pension plans and OPEB balances represent the regulatory offset to pension plan and OPEB obligations to the extent the amounts are expected to be collected from customers in future rates. An OPEB balance of $89 million is being collected over a 20-year period that commenced in 2013, whereas the settlement period for the pension regulatory asset is not determinable. The balances are excluded from the rate base and do not earn an ROE.*

7 *The constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the Site restoration adjustment.*

8 *The future removal and site restoration reserves balance results from amounts collected from customers by certain businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred.*

9 *The site restoration clearance adjustment represents the amount that was determined by the OEB, of previously collected costs for future removal and site restoration that is considered to be in excess of future requirements and will be refunded to customers over the term of the IR Plan. This was a result of the OEB's approval of the adoption of a new approach for determining net salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves.*

10 *The revenue adjustment represents the revenue variance between interim rates, which were in place from January 1, 2014 to September 30, 2014, and the final OEB approved 2014 rates, which were implemented on October 1, 2014, but effective January 1, 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount to be refunded to customers.*

11 *The transaction services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. The balance is expected to be refunded to customers in the following year.*

12 *Transportation revenue adjustments are the cumulative differences between actual expenses incurred and estimated expenses included in transportation tolls. Transportation revenue adjustments are not included in the rate base. The recovery period is approximately five years and dependent on shipper throughput levels.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2014, cumulative costs relating to this consulting contract of $166 million (2013 - $154 million) were included in Property, plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Magic Valley and Wildcat Wind Farms

On December 31, 2014, Enbridge acquired an 80% controlling interest in Magic Valley, a wind farm located in Texas and Wildcat, a wind farm located in Indiana for cash consideration of $394 million (US$340 million). No revenue or earnings were recognized in the year ended December 31, 2014 as the wind farms were acquired on December 31, 2014. The wind farms are included within the Gas Pipelines, Processing and Energy Services segment.

If the acquisition had occurred on January 1, 2013, revenues and earnings for the year ended December 31, 2014 would have increased by $64 million (US$58 million) and $8 million (US$7 million), respectively, and revenues and earnings for the year ended December 31, 2013 would have increased by $44 million (US$43 million) and decreased by $2 million (US$2 million), respectively.

The following purchase price allocation is provisional until the Company completes its valuation of the acquired assets.

December 31,	**2014**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	747
Intangible assets	12
Other long-term liabilities	(14)
Noncontrolling interests[1]	(351)
	394
Purchase price:	
Cash	394

1 *The fair value of the noncontrolling interests was determined using a combination of the implied purchase price for the remaining 20% interest and discounted cash flow models.*

Silver State North Solar Project

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada for cash consideration of $195 million (US$190 million). Silver State expanded the Company's renewable energy business. Revenues and earnings of $10 million and $1 million, respectively, were recognized in the year ended December 31, 2012. No revenues or earnings were recognized in any prior period as the solar project commenced operations in the second quarter of 2012. Silver State is included within the Gas Pipelines, Processing and Energy Services segment.

March 22,	**2012**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Accounts receivable and other[1]	54
Property, plant and equipment	141
	195
Purchase price:	
Cash	195

1 The Company acquired the right to apply for a $54 million (US$55 million) United States Treasury grant under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property. The grant, which was applied for subsequent to commercial operations, was received in October 2012.

OTHER ACQUISITIONS

In December 2014, the Company acquired an incremental 30% interest in the Massif du Sud Wind Project (Massif du Sud) for cash consideration of $102 million, bringing its total interest in the wind project to 80%. The Company acquired its original 50% interest in Massif du Sud in December 2012. The Company's interest in Massif du Sud represents an undivided interest, with $97 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Massif du Sud is currently operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

In October 2014, the Company acquired an incremental 17.5% interest in the Lac Alfred Wind Project (Lac Alfred) for cash consideration of $121 million, bringing its total interest in the wind project to 67.5%. The Company acquired its original 50% interest in Lac Alfred in December 2011. The Company's interest in Lac Alfred represents an undivided interest, with $115 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Lac Alfred is currently operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

In July 2013, the Company acquired a 50% undivided interest in the Saint Robert Bellarmin Wind Project (Saint Robert), located in Quebec for a purchase price of $106 million, of which $100 million was allocated to Property, plant and equipment, with the remainder allocated to Intangible assets. Saint Robert is operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

OTHER DISPOSITIONS

In November 2014, the Company sold one of its non-core assets within Enbridge Offshore Pipelines (Offshore), which include pipeline facilities located in Louisiana, to a third party for $7 million (US$7 million). A gain of $22 million (US$19 million) was presented within Other income/(expense) on the Consolidated Statements of Earnings.

In July 2014, the Company sold a 35% equity interest in the Southern Access Extension Project, a pipeline project under construction, to an unrelated party for gross proceeds of $73 million (US$68 million). As the fair value of the consideration received equalled the carrying value of the asset sold, no gain or loss was recognized on the sale *(Note 11)*.

In March 2014, the Company sold an Alternative and Emerging Technologies investment within the Corporate segment to a third party for $19 million. A gain of $16 million was presented within Other income/(expense) on the Consolidated Statements of Earnings.

In November 2013, EEP sold one of its non-core liquids assets, a storage facility in Kansas, to a third party for $41 million (US$40 million). A gain of $18 million (US$17 million) was presented within Other income/(expense) on the Consolidated Statements of Earnings.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Unbilled revenues	**2,218**	2,773
Trade receivables	**1,168**	1,154
Taxes receivable	**522**	200
Regulatory assets	**567**	54
Short-term portion of derivative assets *(Note 23)*	**568**	385
Prepaid expenses and deposits	**103**	123
Current deferred income taxes *(Note 24)*	**245**	120
Dividends receivable	**26**	26
Other	**129**	159
Allowance for doubtful accounts	**(42)**	(38)
	5,504	4,956

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain of EEP's 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$378 million ($439 million) and US$380 million ($404 million) as at December 31, 2014 and December 31, 2013, respectively.

8. INVENTORY

December 31,	**2014**	2013
(millions of Canadian dollars)		
Natural gas	**678**	527
Other commodities	**470**	588
	1,148	1,115

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $174 million for the year ended December 31, 2014 (2013 - $4 million; 2012 - $10 million) to reduce the cost basis of inventory to market value.

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2014	2013
(millions of Canadian dollars)			
Liquids Pipelines[1]			
Pipeline	2.6%	**12,515**	8,974
Pumping equipment, buildings, tanks and other	3.0%	**7,715**	6,248
Land and right-of-way	1.4%	**520**	253
Under construction	-	**5,578**	4,846
		26,328	20,321
Accumulated depreciation		**(4,312)**	(3,838)
		22,016	16,483
Gas Distribution			
Gas mains, services and other	3.1%	**8,427**	8,020
Land and right-of-way	1.2%	**84**	79
Under construction	-	**352**	179
		8,863	8,278
Accumulated depreciation		**(2,256)**	(2,074)
		6,607	6,204
Gas Pipelines, Processing and Energy Services			
Pipeline	4.2%	**633**	456
Wind turbines, solar panels and other	4.0%	**2,371**	1,092
Power transmission	2.1%	**397**	384
Canadian Midstream gas gathering and processing	2.9%	**778**	557
Land and right-of-way	1.1%	**28**	6
Under construction	-	**1,172**	1,233
		5,379	3,728
Accumulated depreciation		**(454)**	(344)
		4,925	3,384
Sponsored Investments			
Pipeline	3.0%	**11,564**	8,979
Pumping equipment, buildings, tanks and other	3.0%	**7,806**	6,076
Wind turbines, solar panels and other	4.0%	**1,549**	1,548
Land and right-of-way	2.2%	**1,040**	755
Under construction	-	**2,126**	2,201
		24,085	19,559
Accumulated depreciation		**(3,903)**	(3,429)
		20,182	16,130
Corporate			
Other	12.8%	**80**	84
Under construction	-	**69**	36
		149	120
Accumulated depreciation		**(49)**	(42)
		100	78
		53,830	42,279

1 *In July 2014, $62 million of Property, plant and equipment was disposed as part of the sale of 35% equity interest in the Southern Access Extension Project. The remaining balance of $136 million in Property, plant and equipment was reclassified to Long-term investments (Note 11).*

Depreciation expense for the year ended December 31, 2014 was $1,461 million (2013 - $1,282 million; 2012 - $1,174 million).

GAS PIPELINES, PROCESSING AND ENERGY SERVICES
Impairment
In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas of the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

The impairment charge was based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and was presented within Operating and administrative expense on the Consolidated Statements of Earnings. The charge was inclusive of $50 million related to abandonment costs which were reasonably determined given the expected timing and scope of certain asset retirements. A portion of the impairment charge was subsequently reclassified to discontinued operations as discussed below.

Discontinued Operations
In March 2014, the Company completed the sale of certain of its Offshore 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. The results of operations, including revenues of $4 million (2013 - $26 million; 2012 - $32 million) and related cash flows, have also been presented as discontinued operations for the year ended December 31, 2014. At December 31, 2013, the related assets and liabilities were classified as held for sale and were measured at the lower of their carrying amount and estimated fair value less cost to sell which did not result in a fair value adjustment. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

10. VARIABLE INTEREST ENTITIES

The Company is required to consolidate variable interest entities in which the Company is the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company assesses all aspects of its interest in the entity and uses its judgment when determining if the Company is the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE's capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reassessment of the primary beneficiary conclusion is conducted when there are changes in the facts and circumstances related to a VIE.

SPONSORED INVESTMENTS
Enbridge Income Fund
The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 66.4% (2013 - 67.3%; 2012 - 67.7%) economic interest, held indirectly through a common investment in ENF, a direct common trust unit investment in the Fund and a preferred unit investment in a wholly-owned subsidiary of the Fund. Enbridge also serves in the capacity of Manager of ENF, the Fund and its subsidiaries. The creditors of the Fund have no recourse to the general credit of the Company.

The summarized impact of the Company's interest in the Fund on earnings, cash flows and financial position is presented below. Earnings include the results of operations of certain assets and equity interests acquired by the Fund from indirect wholly-owned subsidiaries of Enbridge since their acquisition in December 2012 and November 2014 *(Note 19)*.

Year ended December 31,	2014	2013	2012
(millions of Canadian dollars)			
Revenues	**416**	403	288
Operating and administrative expense	**(135)**	(126)	(83)
Depreciation and amortization	**(136)**	(130)	(87)
Income from equity investments	**72**	57	54
Interest expense	**(59)**	(91)	(68)
Income taxes	**(43)**	(27)	(35)
Earnings	**115**	86	69
Loss attributable to noncontrolling interests	**11**	24	12
Earnings attributable to Enbridge Inc.	**126**	110	81
Cash flows			
Cash provided by operating activities	**277**	260	200
Cash used in investing activities	**(1,806)**	(98)	(160)
Cash provided by/(used in) financing activities	**1,531**	(323)	1,495
Increase/(decrease) in cash and cash equivalents	**2**	(161)	1,535

December 31,	2014	2013
(millions of Canadian dollars)		
Current assets	**114**	84
Property, plant and equipment, net	**2,226**	2,317
Long-term investments	**441**	227
Deferred amounts and other assets[1]	**1,304**	130
Current liabilities	**(149)**	(388)
Long-term debt	**(2,544)**	(1,364)
Other long-term liabilities	**(79)**	(26)
Deferred income taxes	**(441)**	(426)
Net assets before noncontrolling interests	**872**	554

1 *Includes an investment of $945 million in Class A units of Enbridge subsidiaries by the Fund completed in November 2014.*

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Magicat Holdco LLC

Through its 80% controlling interest in Magicat Holdco LLC acquired on December 31, 2014, the Company is the primary beneficiary of the Magic Valley and Wildcat wind farms *(Note 6)*. These wind farms are considered VIEs by virtue of the Company's voting rights and its power to direct the activities that most significantly impact the economic performance of the wind farms.

As at December 31, 2014, the Company's investment in the Magic Valley and Wildcat wind farms was $394 million, with their carrying amounts of assets and liabilities consolidated by the Company of $759 million and $14 million, respectively. The wind farms' assets can only be used to settle their obligations. Enbridge does not have an obligation to provide financial support to these VIEs other than an indirect obligation, as prescribed by the terms of certain indemnities and guarantees, to pay the liabilities of the wind farms in the event of a default.

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2014**	2013
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Seaway Pipeline	50.0%	**2,782**	2,048
Chicap Pipeline	43.8%	**33**	29
Mustang Pipeline	30.0%	**25**	23
Southern Access Extension	65.0%	**263**	-
Other	75.0%	**7**	-
Gas Pipelines, Processing and Energy Services			
Aux Sable	42.7% - 50.0%	**311**	306
Alliance Pipeline US[1]	-	**-**	201
Vector Pipeline	60.0%	**141**	125
Offshore - various joint ventures	22.0% - 74.3%	**429**	401
Other	33.3% - 70.0%	**12**	11
Sponsored Investments			
Texas Express Pipeline	35.0%	**442**	396
Alliance Pipeline Canada and US[1]	50.0%	**374**	165
Other	50.0%	**67**	62
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	**-**	-
Other	19.3% - 49.99%	**45**	56
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		**323**	287
Other		**154**	102
		5,408	4,212

1 In November 2014, Enbridge's interest in Alliance Pipeline US was transferred to the Fund. As a result, $203 million of Long-term investments as at December 31, 2014 were reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The Alliance Pipeline US balance of $201 million in Gas Pipelines, Processing and Energy Services as at December 31, 2013 has not been reclassified for presentation purposes.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date, which is comprised of $742 million (2013 - $680 million) in Goodwill and $494 million (2013 - $517 million) in amortizable assets.

JOINT VENTURES

Summarized combined financial information of the Company's interest in unconsolidated equity investments in joint ventures is as follows:

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Revenues	**1,790**	1,212	956
Commodity costs	**(661)**	(371)	(236)
Operating and administrative expense	**(360)**	(268)	(244)
Depreciation and amortization	**(232)**	(175)	(159)
Other income/(expense)	**(1)**	4	4
Interest expense	**(84)**	(74)	(81)
Earnings before income taxes	**452**	328	240

December 31,	**2014**	2013
(millions of Canadian dollars)		
Current assets	**472**	366
Property, plant and equipment, net	**5,169**	4,050
Deferred amounts and other assets	**34**	35
Intangible assets, net	**77**	75
Goodwill	**742**	680
Current liabilities	**(712)**	(395)
Long-term debt	**(811)**	(994)
Other long-term liabilities	**(85)**	(50)
Net assets	**4,886**	3,767

Alliance Pipeline System

Certain assets of the Alliance Pipeline System (Alliance System) are pledged as collateral to Alliance System lenders.

Southern Access Extension Project

On July 1, 2014, under an agreement with an unrelated third party, the Company sold a 35% equity interest in the Southern Access Extension Project (the Project). Prior to this sale, the subsidiary executing the Project was wholly-owned and consolidated within the Liquids Pipelines segment. The Company concluded that under the agreement, the purchaser of the 35% equity interest is entitled to substantive participating rights; however, the Company continues to exercise significant influence. As a result, effective July 1, 2014, the Company discontinued consolidation of the Project and recognized its remaining 65% equity interest as a long-term equity investment within the Liquids Pipelines segment.

OTHER EQUITY INVESTMENTS

Noverco

As at December 31, 2014, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2013 - 38.9%; 2012 - 38.9%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

As at December 31, 2014, Noverco owned an approximate 3.6% (2013 - 3.9%; 2012 - 6.0%) reciprocal shareholding in common shares of Enbridge. The change in reciprocal shareholding compared with prior years reflected the sale of Enbridge common shares by Noverco. Through secondary offerings, Noverco sold 22.5 million Enbridge common shares in 2012, 15 million common shares in 2013 and a further 1.3 million common shares in 2014. The transactions were recognized as issuances of treasury stock on the Consolidated Statements of Changes in Equity. In relation to the 2012 and 2013 transactions, Enbridge's share of the net after-tax proceeds of $297 million and $248 million were received as dividends from Noverco in May 2012 and June 2013, respectively, and reflected in Operating activities on the Consolidated Statements of Cash Flows.

As a result of Noverco's reciprocal shareholding in Enbridge common shares, the Company has an indirect pro-rata interest of 1.4% (2013 - 1.5%; 2012 - 2.1%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $83 million at December 31, 2014 (2013 - $86 million; 2012 - $126 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco.

12. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets	**1,752**	1,172
Long-term portion of derivative assets *(Note 23)*	**199**	413
Affiliate long-term note receivable *(Note 28)*	**183**	185
Contractual receivables	**382**	356
Deferred financing costs	**166**	135
Other	**526**	401
	3,208	2,662

As at December 31, 2014, deferred amounts of $366 million (2013 - $307 million) were subject to amortization and are presented net of accumulated amortization of $189 million (2013 - $159 million). Amortization expense for the year ended December 31, 2014 was $38 million (2013 - $34 million; 2012 - $25 million).

13. INTANGIBLE ASSETS

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.9%	**1,049**	**337**	**712**
Natural gas supply opportunities	3.7%	**340**	**83**	**257**
Power purchase agreements	3.8%	**96**	**10**	**86**
Transportation agreements	3.7%	**56**	**18**	**38**
Other	3.6%	**85**	**12**	**73**
		1,626	**460**	**1,166**

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.2%	825	241	584
Natural gas supply opportunities	3.7%	311	65	246
Power purchase agreements	4.0%	87	7	80
Transportation agreements	3.7%	53	15	38
Other	4.0%	64	8	56
		1,340	336	1,004

Total amortization expense for intangible assets was $106 million (2013 - $82 million; 2012 - $64 million) for the year ended December 31, 2014. The Company expects amortization expense for intangible assets for the years ending December 31, 2015 through 2019 of $109 million, $96 million, $85 million, $76 million and $67 million, respectively.

14. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2013	22	-	13	384	-	419
Foreign exchange and other	1	-	1	24	-	26
Balance at December 31, 2013	23	-	14	408	-	445
Foreign exchange and other	**3**	**-**	**1**	**34**	**-**	**38**
Balance at December 31, 2014	**26**	**-**	**15**	**442**	**-**	**483**

The Company did not recognize any goodwill impairments for the years ended December 31, 2014 and 2013.

15. ACCOUNTS PAYABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Operating accrued liabilities	**2,939**	3,577
Trade payables	**414**	300
Construction payables	**746**	1,188
Current derivative liabilities *(Note 23)*	**1,020**	837
Contractor holdbacks	**368**	211
Taxes payable	**555**	176
Security deposits	**63**	65
Asset retirement obligations *(Note 18)*	**53**	-
Other	**286**	310
	6,444	6,664

16. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2014**	2013
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.2%	2024	**200**	200
Medium-term notes[1]	4.8%	2015-2043	**2,986**	2,985
Southern Lights project financing[2,3]	4.0%	2040	**1,571**	1,480
Commercial paper and credit facility draws			**163**	266
Other[4]			**9**	11
Gas Distribution				
Debentures	9.9%	2024	**85**	85
Medium-term notes	4.7%	2016-2050	**3,033**	2,702
Commercial paper and credit facility draws			**939**	374
Sponsored Investments				
Junior subordinated notes[5]	8.1%	2067	**464**	425
Medium-term notes	3.9%	2016-2044	**2,405**	1,615
Senior notes[6]	6.1%	2016-2040	**4,815**	4,201
Commercial paper and credit facility draws[7]			**2,614**	717
Corporate				
United States dollar term notes[8]	3.5%	2015-2044	**3,886**	2,393
Medium-term notes	4.3%	2015-2064	**6,048**	4,518
Commercial paper and credit facility draws[9]			**6,182**	3,598
Gas Pipelines, Processing and Energy Services				
Promissory Note[10]		2015	**103**	-
Other[11]			**(35)**	(28)
Total debt			**35,468**	25,542
Current maturities			**(1,004)**	(2,811)
Short-term borrowings[12]			**(1,041)**	(374)
Long-term debt			**33,423**	22,357

1 Included in medium-term notes is $100 million with a maturity date of 2112.
2 2014 - $348 million and US$1,054 million (2013 - $352 million and US$1,061 million).
3 On August 18, 2014, long-term private debt was issued with the proceeds utilized to repay the construction credit facilities on a dollar-for-dollar basis.
4 Primarily capital lease obligations.
5 2014 - US$400 million (2013 - US$400 million).
6 2014 - US$4,150 million (2013 - US$3,950 million).
7 2014 - $140 million and US$2,132 million (2013 - $41 million and US$635 million).
8 2014 - US$3,350 million (2013 - US$2,250 million).
9 2014 - $3,217 million and US$2,555 million (2013 - $2,476 million and US$1,055 million).
10 A non-interest bearing demand promissory note that was subsequently paid on January 9, 2015.
11 Primarily debt discount.
12 Weighted average interest rate - 1.4% (2013 - 1.1%).

For the years ending December 31, 2015 through 2019, debenture and term note maturities are $1,001 million, $1,834 million, $2,429 million, $1,075 million, $1,742 million, respectively, and $17,411 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2015 through 2019 are $1,432 million, $1,404 million, $1,312 million, $1,170 million and $991 million, respectively. At December 31, 2014, all debt is unsecured and at December 31, 2013, all debt is unsecured except for the Southern Lights project financing which was collateralized by the Southern Lights project assets of approximately $2,680 million.

INTEREST EXPENSE

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Debentures and term notes	**1,425**	1,123	986
Commercial paper and credit facility draws	**71**	34	33
Southern Lights project financing	**49**	40	38
Capitalized	**(416)**	(250)	(216)
	1,129	947	841

CREDIT FACILITIES

The following table provides details of the Company's committed credit facilities at December 31, 2014 and December 31, 2013.

		December 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**163**	**137**	300
Gas Distribution	2016-2019	**1,008**	**943**	**65**	707
Sponsored Investments	2016-2019	**4,531**	**2,745**	**1,786**	4,781
Corporate	2016-2019	**12,772**	**6,223**	**6,549**	11,775
Total committed credit facilities[2]		**18,611**	**10,074**	**8,537**	17,563

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

2 On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis. Excluded from December 31, 2014 total facilities above was Southern Lights project financing facilities of $28 million (2013 - $1,570 million). Included in the 2013 facilities for Southern Lights were $63 million for debt service reserve letters of credit.

In addition to the committed credit facilities noted above, the Company also has $361 million (2013 - $35 million) of uncommitted demand credit facilities, of which $80 million (2013 - $17 million) was unutilized as at December 31, 2014.

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 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $8,960 million (2013 - $4,580 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2014, the Company was in compliance with all debt covenants.

17. OTHER LONG-TERM LIABILITIES

December 31,	2014	2013
(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 5)*	**757**	929
Derivative liabilities *(Note 23)*	**2,078**	1,395
Pension and OPEB liabilities *(Note 25)*	**584**	264
Asset retirement obligations *(Note 18)*	**132**	24
Environmental liabilities	**70**	28
Other	**420**	298
	4,041	2,938

18. ASSET RETIREMENT OBLIGATIONS

Included in ARO at December 31, 2014 was an amount of $21 million (2013 - $20 million) for the retirement of certain assets of the Fund which is estimated to be settled between 2016 and 2060. During the year ended December 31, 2014, the Company recognized ARO in the amount of $177 million. Of the amount, $74 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System and $103 million related to the Canadian and United States portions of the Line 3 Replacement

Program targeted to be completed in 2017 whereby the Company will replace the existing Line 3 pipeline in Canada and the United States.

The liability for the expected cash flows as recognized in the financial statements reflected discount rates ranging from 4.6% to 8.1% (2013 - 8.1%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Obligations, beginning of year	**24**	23
Liabilities incurred	**177**	-
Liabilities settled	**(24)**	-
Foreign currency translation adjustment	**5**	-
Accretion expense	**3**	1
Obligations, end of year	**185**	24
Presented as follows:		
Accounts payable and other *(Note 15)*	**53**	-
Other long-term liabilities *(Note 17)*	**132**	24
	185	24

19. NONCONTROLLING INTERESTS

December 31,	**2014**	2013
(millions of Canadian dollars)		
EEP	**748**	2,810
Enbridge Energy Management, L.L.C. (EEM)	**790**	1,079
Renewable energy assets *(Note 6)*	**351**	-
EGD preferred shares	**100**	100
Other	**26**	25
	2,015	4,014

Noncontrolling interests in EEP represented the 79.5% (2013 - 79.4%) interest in EEP held by public unitholders, as well as interests of third parties in subsidiaries of EEP, including Midcoast Energy Partners, L.P. (MEP). The decrease in noncontrolling interests in EEP reflected the EEP equity restructuring effective July 1, 2014. Enbridge Energy Company, Inc., a wholly-owned subsidiary of Enbridge and the General Partner (GP) of EEP, entered into an equity restructuring transaction in which the Company irrevocably waived its right to receive cash distributions and allocations in excess of 2% in respect of its GP interest in the existing incentive distribution rights in exchange for the issuance of (i) 66.1 million units of a new class of EEP units designated as Class D Units, and (ii) 1,000 units of a new class of EEP units designated as Incentive Distribution Units (IDU). The Class D Units entitle the Company to receive quarterly distributions equal to the distribution paid on EEP's common units. This restructuring decreases the Company's share of incremental cash distributions from 48% of all distributions in excess of US$0.495 per unit per quarter down to 23% of all distributions in excess of EEP's current quarterly distribution of US$0.5435 per unit per quarter. The transaction applies to all distributions declared subsequent to the effective date. EEP recorded the Class D Units and IDU at fair value, which resulted in a reduction to the carrying amounts of the GP and limited partner capital accounts on a pro-rata basis. As a result, the Company recorded a decrease in Noncontrolling interests of $2,363 million inclusive of CTA and increases in Additional paid-in capital and Deferred income tax liabilities of $1,601 million and $762 million, respectively.

During the year ended December 31, 2014, EEP distributed $504 million (2013 - $463 million; 2012 - $419 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

In May 2013, EEP formed MEP as its wholly-owned subsidiary. Subsequently, on November 13, 2013, MEP completed its initial public offering of 18.5 million Class A common units representing limited partner interests and subsequently issued an additional 2.8 million Class A common units pursuant to an underwriters' over-allotment option. MEP received proceeds of approximately $372 million (US$355 million). Upon finalization of the offering, MEP's initial assets consisted of an approximate 39% ownership interest in EEP's natural gas and NGL midstream business. EEP retained a 2% GP interest, an approximate 52% limited partner interest and all incentive distribution rights (IDR) in MEP, in addition to its 61% direct interest in the natural gas and NGL midstream assets.

On July 1, 2014, EEP completed the sale of an additional 12.6% limited partnership interest in its natural gas and NGL midstream business to MEP for cash proceeds of $376 million (US$350 million). Upon finalization of this transaction, EEP continued to retain a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP. However, EEP's direct interest in entities or partnerships holding the natural gas and NGL midstream operations reduced from 61% to 48%, with the remaining ownership held by MEP.

Noncontrolling interests in Enbridge Energy Management, LLC (EEM) represented the 88.3% (2013 - 88.3%) of the listed shares of EEM not held by the Company. The decrease in the carrying value of the Noncontrolling interests in EEM is due to the fair value allocation attributable to EEM as a result of the EEP equity restructuring as discussed above. In 2013, EEM completed a listed share issuance in which the Company did not participate and which resulted in contributions of $523 million from noncontrolling interest holders.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2014, no preferred shares have been redeemed.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Balance at beginning of year	**1,053**	1,000	640
Loss	**(11)**	(24)	(12)
Other comprehensive income/(loss)			
Change in unrealized gains/(loss) on cash flow hedges, net of tax	**(15)**	4	(1)
Change in foreign currency translation adjustment	**5**	-	-
Other comprehensive income/(loss)	**(10)**	4	(1)
Distributions to unitholders	**(79)**	(72)	(49)
Contributions from unitholders	**323**	92	225
Redemption value adjustment	**973**	53	197
Balance at end of year	**2,249**	1,053	1,000

Redeemable noncontrolling interests in the Fund at December 31, 2014 represented 70.6% (2013 - 68.6%; 2012 - 67.7%) of interests in the Fund's trust units that are held by third parties. In November 2014, the Fund acquired Enbridge's 50% interest in Alliance Pipeline US and subscribed for and purchased Class A units of Enbridge's subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline for a total consideration of approximately $1.8 billion, including $421 million in cash, $878 million in the form of a long-term note payable by the Fund, bearing interest of 5.5% per annum and was fully repaid at December 31, 2014, and $461 million in the form of preferred units of Enbridge Commercial Trust, a subsidiary of the Fund. To fund the cash component of the consideration, the Fund issued approximately $421 million of trust units to ENF. To purchase the trust units from the Fund, ENF completed a bought deal public offering of common shares for approximately $337 million and issued additional common shares to Enbridge for approximately $84 million in order for Enbridge to maintain its 19.9% interest in ENF. As a result of the transfer, redeemable noncontrolling interests in the Fund increased from 68.6% to 70.6% and contributions of $323 million, net of share issue costs, were received from redeemable noncontrolling interest holders.

During the year ended December 31, 2013, the Fund completed a unit issuance in which the Company did not participate, resulting in an increase in the redeemable noncontrolling interests from 67.7% to 68.6%. This resulted in contributions of $92 million from redeemable noncontrolling interest holders.

In December 2012, the Fund acquired Greenwich Wind Energy Project, Amherstburg Solar Project, Tilbury Solar Project, Hardisty Caverns and Hardisty Contract Terminals from Enbridge and wholly-owned subsidiaries of Enbridge for proceeds of $1.2 billion. Trust units were issued by the Fund to partially finance this acquisition, resulting in an increase in interests held by third parties in 2012 and contributions from noncontrolling unitholders of $225 million.

Distributions to noncontrolling unitholders were made on a monthly basis for the years ended December 31, 2014, 2013 and 2012 in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2014		2013		2012	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**831**	**5,744**	805	4,732	781	3,969
Common Shares issued[1]	**9**	**446**	13	582	10	388
Dividend Reinvestment and Share Purchase Plan (DRIP)	**9**	**428**	8	361	8	297
Shares issued on exercise of stock options	**3**	**51**	5	69	6	78
Balance at end of year	**852**	**6,669**	831	5,744	805	4,732

1 *Gross proceeds - $460 million (2013 - $600 million; 2012 - $400 million); net issuance costs - $14 million (2013 - $18 million; 2012 - $12 million).*

PREFERENCE SHARES

December 31,	2014 Number of Shares	2014 Amount	2013 Number of Shares	2013 Amount	2012 Number of Shares	2012 Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J	**8**	**199**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	-	-
Preference Shares, Series 3	**24**	**600**	24	600	-	-
Preference Shares, Series 5	**8**	**206**	8	206	-	-
Preference Shares, Series 7	**10**	**250**	10	250	-	-
Preference Shares, Series 9	**11**	**275**	-	-	-	-
Preference Shares, Series 11	**20**	**500**	-	-	-	-
Preference Shares, Series 13	**14**	**350**	-	-	-	-
Preference Shares, Series 15	**11**	**275**	-	-	-	-
Issuance costs		**(137)**		(111)		(78)
Balance at end of period		**6,515**		5,141		3,707

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.0%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.0%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.4%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7	4.4%	$1.100	$25	March 1, 2019	Series 8
Preference Shares, Series 9	4.4%	$1.100	$25	December 1, 2019	Series 10
Preference Shares, Series 11	4.4%	$1.100	$25	March 1, 2020	Series 12
Preference Shares, Series 13	4.4%	$1.100	$25	June 1, 2020	Series 14
Preference Shares, Series 15	4.4%	$1.100	$25	September 1, 2020	Series 16

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*

2 *Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, the Company, may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G),*

2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14) or 2.7% (Series 16); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).

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 (2013 - 15 million; 2012 - 20 million) resulting from the Company's reciprocal investment in Noverco.

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.

December 31,	**2014**	2013	2012
(number of common shares in millions)			
Weighted average shares outstanding	**829**	806	772
Effect of dilutive options	**11**	11	13
Diluted weighted average shares outstanding	**840**	817	785

For the year ended December 31, 2014, 6,058,580 anti-dilutive stock options (2013 - 6,327,500; 2012 - 5,733,000) with a weighted average exercise price of $48.78 (2013 - $44.85; 2012 - $38.32) were excluded from the diluted earnings per common share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 49 million have been issued to date. A further 71 million common shares have been reserved for issuance for the 2007 ISO and PBSO plans, of which eight million have been exercised and issued from treasury to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISO to purchase common shares at the market price on the grant date. ISO vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**29,602**	**30.52**		
Options granted	**5,963**	**48.80**		
Options exercised[1]	**(3,973)**	**22.20**		
Options cancelled or expired	**(262)**	**41.33**		
Options outstanding at end of year	**31,330**	**34.97**	**6.6**	**523**
Options vested at end of year[2]	**16,591**	**27.25**	**5.2**	**405**

1 The total intrinsic value of ISO exercised during the year ended December 31, 2014 was $117 million (2013 - $98 million; 2012 - $130 million) and cash received on exercise was $37 million (2013 - $24 million; 2012 - $69 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2014 was $26 million (2013 - $22 million; 2012 - $19 million).

Weighted average assumptions used to determine the fair value of ISO granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	2014	2013	2012
Fair value per option *(Canadian dollars)*[1]	**5.53**	5.27	4.81
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**16.9%**	17.4%	19.7%
Expected dividend yield[4]	**2.9%**	2.8%	3.0%
Risk-free interest rate[5]	**1.6%**	1.2%	1.3%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.45 (2013 - $5.15; 2012 - $4.65) for Canadian employees and US$5.35 (2013 - US$5.63; 2012 - US$5.58) for United States employees.

2 The expected option term is based on historical exercise practice.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2014 for ISO was $29 million (2013 - $27 million; 2012 - $23 million). At December 31, 2014, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $42 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE BASED STOCK OPTIONS

PBSO are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSO were granted on August 15, 2007, February 19, 2008, August 15, 2012 and March 13, 2014 under the 2007 plan. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements were fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. Currently, two of the three performance targets have been met as at December 31, 2014 and the options are exercisable until August 15, 2020. Time vesting requirements for the 2014 grant will be fulfilled evenly over a four-year term, ending March 13, 2018. The 2014 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. Currently, one of the two performance targets have been met as at December 31, 2014 and the options are exercisable until August 15, 2020.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**4,373**	**35.56**		
Options granted	**138**	**48.81**		
Options exercised[1]	**-**	**-**		
Options outstanding at end of year	**4,511**	**35.97**	**4.5**	**71**
Options vested at end of year[2]	**1,964**	**30.93**	**3.4**	**41**

1 No PBSO were exercised in 2014. The total intrinsic value of PBSO exercised during the year ended December 31, 2013 and 2012 was $62 million and $20 million, respectively, and cash received on exercise was $28 million and $12 million.

2 The total fair value of options vested under the PBSO Plan during the year ended December 31, 2014 was $5 million (2013 - nil; 2012 - $1 million).

Assumptions used to determine the fair value of PBSO granted using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2014**	2012
Fair value per option *(Canadian dollars)*	**5.77**	4.25
Valuation assumptions		
Expected option term *(years)*[1]	**6.5**	8
Expected volatility[2]	**15.0%**	16.1 %
Expected dividend yield[3]	**2.8%**	2.8%
Risk-free interest rate[4]	**1.7%**	1.6%

1 The expected option term is based on historical exercise practice.

2 Expected volatility is determined with reference to historic daily share price volatility.

3 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

4 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.

Compensation expense recorded for the year ended December 31, 2014 for PBSO was $3 million (2013 - $3 million; 2012 - $2 million). At December 31, 2014, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $9 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two if the Company performs within the highest range of its performance targets. The 2012, 2013 and 2014 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2014 expense, multipliers of two, based upon multiplier estimates at December 31, 2014, were used for each of the 2012, 2013 and 2014 PSU grants.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**591**		
Units granted	**274**		
Units cancelled	**(2)**		
Units matured[1]	**(332)**		
Dividend reinvestment	**24**		
Units outstanding at end of year	**555**	**1.5**	**66**

1 The total amount paid during the year ended December 31, 2014 for PSU was $36 million (2013 - $48 million; 2012 - $25 million).

Compensation expense recorded for the year ended December 31, 2014 for PSU was $40 million (2013 - $25 million; 2012 - $49 million). As at December 31, 2014, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $34 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**1,828**		
Units granted	**1,019**		
Units cancelled	**(99)**		
Units matured[1]	**(867)**		
Dividend reinvestment	**78**		
Units outstanding at end of year	**1,959**	**1.5**	**116**

1 The total amount paid during the year ended December 31, 2014 for RSU was $45 million (2013 - $41 million; 2012 - $37 million).

Compensation expense recorded for the year ended December 31, 2014 for RSU was $44 million (2013 - $36 million; 2012 - $32 million). As at December 31, 2014, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $58 million and is expected to be fully recognized over a weighted average period of approximately two years.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2014, 2013 and 2012, are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	**(1)**	**378**	**(778)**	**(15)**	**(183)**	**(599)**
Other comprehensive income/(loss) retained in AOCI	**(857)**	**(301)**	**1,087**	**10**	**(265)**	**(326)**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**201**	**-**	**-**	**-**	**-**	**201**
Commodity contracts[2]	**(2)**	**-**	**-**	**-**	**-**	**(2)**
Foreign exchange contracts[3]	**8**	**-**	**-**	**-**	**-**	**8**
Other contracts[4]	**(23)**	**-**	**-**	**-**	**-**	**(23)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**-**	**-**	**-**	**-**	**18**	**18**
	(673)	**(301)**	**1,087**	**10**	**(247)**	**(124)**
Tax impact						
Income tax on amounts retained in AOCI	**231**	**31**	**-**	**-**	**74**	**336**
Income tax on amounts reclassified to earnings	**(45)**	**-**	**-**	**-**	**(3)**	**(48)**
	186	**31**	**-**	**-**	**71**	**288**
Balance at December 31, 2014	**(488)**	**108**	**309**	**(5)**	**(359)**	**(435)**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	(621)	474	(1,265)	(26)	(324)	(1,762)
Other comprehensive income/(loss) retained in AOCI	707	(111)	487	11	165	1,259
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	134	-	-	-	-	134
Commodity contracts[2]	(1)	-	-	-	-	(1)
Foreign exchange contracts[3]	(8)	-	-	-	-	(8)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	36	36
	832	(111)	487	11	201	1,420
Tax impact						
Income tax on amounts retained in AOCI	(176)	15	-	-	(51)	(212)
Income tax on amounts reclassified to earnings	(36)	-	-	-	(9)	(45)
	(212)	15	-	-	(60)	(257)
Balance at December 31, 2013	(1)	378	(778)	(15)	(183)	(599)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
Balance at January 1, 2012	(476)	461	(1,167)	(28)	(286)	(1,496)
Other comprehensive income/(loss) retained in AOCI	(172)	16	(98)	7	(75)	(322)
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	(17)	-	-	-	-	(17)
Commodity contracts[2]	(4)	-	-	-	-	(4)
Foreign exchange contracts[3]	1	-	-	-	-	1
Other contracts[4]	2	-	-	-	-	2
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	23	23
	(190)	16	(98)	7	(52)	(317)
Tax impact						
Income tax on amounts retained in AOCI	36	(3)	-	(5)	19	47
Income tax on amounts reclassified to earnings	9	-	-	-	(5)	4
	45	(3)	-	(5)	14	51
Balance at December 31, 2012	(621)	474	(1,265)	(26)	(324)	(1,762)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
3 *Reported within Other income/(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.*

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and 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 2.1%.

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 4.1%.

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 uses primarily 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 interests 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, RSU. 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 as at December 31, 2014 or December 31, 2013.

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 amount in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

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
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
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 *(Note 12)*						
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 *(Note 15)*						
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 *(Note 17)*						
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.

December 31, 2013	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[1]	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	16	11	51	78	(26)	52
Interest rate contracts	171	-	12	183	(27)	156
Commodity contracts	4	-	114	118	(64)	54
Other contracts	2	-	4	6	-	6
	193	11	181	385	(117)	268
Deferred amounts and other assets *(Note 12)*						
Foreign exchange contracts	7	33	27	67	(62)	5
Interest rate contracts	249	-	1	250	(47)	203
Commodity contracts	9	-	86	95	(67)	28
Other contracts	1	-	-	1	-	1
	266	33	114	413	(176)	237
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	(2)	(4)	(69)	(75)	26	(49)
Interest rate contracts	(387)	-	(16)	(403)	45	(358)
Commodity contracts	(14)	-	(345)	(359)	64	(295)
	(403)	(4)	(430)	(837)	135	(702)
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	(4)	(31)	(435)	(470)	62	(408)
Interest rate contracts	(68)	-	(1)	(69)	29	(40)
Commodity contracts	(2)	-	(854)	(856)	67	(789)
	(74)	(31)	(1,290)	(1,395)	158	(1,237)
Total net derivative asset/(liability)						
Foreign exchange contracts	17	9	(426)	(400)	-	(400)
Interest rate contracts	(35)	-	(4)	(39)	-	(39)
Commodity contracts	(3)	-	(999)	(1,002)	-	(1,002)
Other contracts	3	-	4	7	-	7
	(18)	9	(1,425)	(1,434)	-	(1,434)

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

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 *(megawatt hours (MWH))*	**25**	**40**	**40**	**30**	**31**	**-**

December 31, 2013	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	710	25	25	413	2	4
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,795	2,751	2,323	2,557	1,649	3,771
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	5	28	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,007	5,210	5,030	3,965	274	267
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	5,736	1,779	1,814	1,090	-	-
Equity contracts *(millions of Canadian dollars)*	40	41	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	17	(8)	10	11	46	-
Commodity contracts - crude oil *(millions of barrels)*	(34)	(29)	(23)	(18)	(9)	-
Commodity contracts - NGL *(millions of barrels)*	(10)	(2)	-	-	-	-
Commodity contracts - power *(MWH)*	55	5	20	40	30	8

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.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**8**	56	(12)
Interest rate contracts	**(1,086)**	814	(46)
Commodity contracts	**50**	(9)	52
Other contracts	**13**	(2)	(3)
Net investment hedges			
Foreign exchange contracts	**(113)**	(81)	1
	(1,128)	778	(8)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	**8**	(8)	1
Interest rate contracts[2]	**101**	107	(1)
Commodity contracts[3]	**4**	1	(3)
Other contracts[4]	**(7)**	-	2
	106	100	(1)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**216**	51	23
Commodity contracts[3]	**(6)**	(3)	(3)
	210	48	20

1 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
2 *Reported as an increase/(decrease) within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $64 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 49 months as at December 31, 2014.

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.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(936)**	(738)	120
Interest rate contracts[2]	**4**	(10)	(2)
Commodity contracts[3]	**1,031**	(496)	(765)
Other contracts[4]	**7**	(3)	(2)
Total unrealized derivative fair value gains/(loss)	**106**	(1,247)	(649)

1 Reported within Transportation and other services revenues (2014 - $496 million loss; 2013 - $352 million loss; 2012 - $150 million gain) and Other income/(expense) (2014 - $440 million loss; 2013 - $386 million loss; 2012 - $30 million loss) in the Consolidated Statements of Earnings.

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

3 Reported within Transportation and other services revenues (2014 - $741 million gain; 2013 - $375 million loss; 2012 - $681 million loss), Commodity costs (2014 - $303 million gain; 2013 - $35 million loss; 2012 - $21 million loss) and Operating and administrative expense (2014 - $13 million loss; 2013 - $86 million loss; 2012 - $63 million loss) in the Consolidated Statements of Earnings.

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

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. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company 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 December 31, 2014. 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:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Canadian financial institutions	**58**	230
United States financial institutions	**240**	227
European financial institutions	**73**	192
Other[1]	**310**	97
	681	746

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

As at December 31, 2014, the Company had provided letters of credit totalling $382 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The

Company held $33 million of cash collateral on derivative asset exposures at December 31, 2014 and $18 million of cash collateral at December 31, 2013.

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 at 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.

Fair Value of Derivatives

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

December 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
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)**

December 31, 2013	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	78	-	78
Interest rate contracts	-	183	-	183
Commodity contracts	6	42	70	118
Other contracts	-	6	-	6
	6	309	70	385
Long-term derivative assets				
Foreign exchange contracts	-	67	-	67
Interest rate contracts	-	250	-	250
Commodity contracts	-	72	23	95
Other contracts	-	1	-	1
	-	390	23	413
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(75)	-	(75)
Interest rate contracts	-	(403)	-	(403)
Commodity contracts	(9)	(248)	(102)	(359)
	(9)	(726)	(102)	(837)
Long-term derivative liabilities				
Foreign exchange contracts	-	(470)	-	(470)
Interest rate contracts	-	(69)	-	(69)
Commodity contracts	-	(701)	(155)	(856)
	-	(1,240)	(155)	(1,395)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(400)	-	(400)
Interest rate contracts	-	(39)	-	(39)
Commodity contracts	(3)	(835)	(164)	(1,002)
Other contracts	-	7	-	7
	(3)	(1,267)	(164)	(1,434)

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

December 31, 2014	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	(7)	Forward gas price	2.95	4.31	3.57	$/mmbtu[3]
Crude	1	Forward crude price	77.31	83.90	83.58	$/barrel
NGL	48	Forward NGL price	0.50	1.33	0.70	$/gallon
Power	(144)	Forward power price	33.25	76.84	54.44	$/MWH
Commodity contracts - physical[1]						
Natural gas	(22)	Forward gas price	1.79	4.85	3.39	$/mmbtu[3]
Crude	123	Forward crude price	33.71	107.48	62.95	$/barrel
NGL	26	Forward NGL price	0.07	1.40	0.81	$/gallon
Commodity options[2]						
Crude	36	Option volatility	27%	40%	32%	
NGL	88	Option volatility	19%	94%	39%	
	149					

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:

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(164)**	(24)
Total gains/(loss)		
Included in earnings[1]	**252**	(100)
Included in OCI	**32**	-
Settlements	**29**	(40)
Level 3 net derivative liability at end of period	**149**	(164)

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 of the last day of the reporting period. There were no transfers between levels as at December 31, 2014 or 2013.

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 $99 million at December 31, 2014 (2013 - $103 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $323 million as at December 31, 2014 (2013 - $287 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 December 31, 2014, the fair value of this preferred share investment approximates its face value of $580 million (2013 - $580 million).

As at December 31, 2014, the Company's long-term debt had a carrying value of $34,427 million (2013 - $25,168 million) and a fair value of $36,637 million (2013 - $27,469 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 year ended December 31, 2014, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of $199 million (2013 - unrealized loss of $46 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of $114 million (2013 - unrealized loss of $80 million) in OCI. The Company also recognized a realized gain of $10 million (2013 - realized gain of $15 million) in OCI associated with the settlement of foreign exchange forward contracts that had matured during the period. There was no ineffectiveness during the year ended December 31, 2014 (2013 - nil).

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**2,173**	613	1,186
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**326**	92	178
Increase/(decrease) resulting from:			
Provincial and state income taxes	**(36)**	(1)	97
Foreign and other statutory rate differentials[1]	**394**	45	(69)
Effects of rate-regulated accounting[5]	**(97)**	(55)	(38)
Foreign allowable interest deductions[5]	**(65)**	(39)	(24)
Part VI.1 tax, net of federal Part I deduction[2,5]	**47**	23	19
Intercompany sale of investment[3,5]	**68**	-	33
Noncontrolling interests[5]	**(28)**	26	(32)
Other[4,5]	**2**	32	7
Income taxes on earnings before discontinued operations	**611**	123	171
Effective income tax rate	**28.1%**	20.1%	14.4%

1 The higher effective income tax rate for 2014 reflected the increase in earnings in the Company's United States operations and the higher United States federal statutory rate over the Canadian federal statutory rate.

2 Represents Part VI.1 tax on preference share dividend distributions, net of an allowed federal deduction. For 2013, this tax was presented net of an $11 million federal tax recovery related to changes to tax law enacted during the year.

3 In November 2014 and December 2012, Enbridge sold certain assets to the Fund. As these transactions occurred between entities under common control of the Company, the intercompany gains realized on these transfers were eliminated. However, because these transactions involved the sale of shares and partnership units, tax consequences have been recognized in earnings. This resulted in a tax expense of $157 million and $56 million in 2014 and 2012, respectively.

4 Other for 2013 includes $55 million related to the federal component of the tax effect of adjustments related to prior periods.

5 The provincial or state tax component of these items is included in the "Provincial and state income taxes" above.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations			
Canada	**114**	193	1,037
United States	**1,614**	132	(58)
Other	**445**	288	207
	2,173	613	1,186
Current income taxes			
Canada	**35**	(30)	130
United States	**(15)**	18	35
Other	**4**	4	3
	24	(8)	168
Deferred income taxes			
Canada	**(193)**	31	160
United States	**780**	100	(157)
	587	131	3
Income taxes on earnings before discontinued operations	**611**	123	171

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(2,668)**	(1,984)
Investments	**(2,469)**	(1,226)
Regulatory assets	**(240)**	(248)
Other	**(102)**	(115)
Total deferred income tax liabilities	**(5,479)**	(3,573)
Deferred income tax assets		
Financial instruments	**644**	487
Pension and OPEB plans	**203**	128
Loss carryforwards	**390**	129
Other	**246**	68
Total deferred income tax assets	**1,483**	812
Less valuation allowance	**(42)**	(28)
Total deferred income tax assets, net	**1,441**	784
Net deferred income tax liabilities	**(4,038)**	(2,789)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**245**	120
Deferred income taxes	**561**	16
Total deferred income tax assets	**806**	136
Liabilities		
Accounts payable and other	**(2)**	-
Deferred income taxes	**(4,842)**	(2,925)
Total deferred income tax liabilities	**(4,844)**	(2,925)
Net deferred income tax liabilities	**(4,038)**	(2,789)

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2014, the Company recognized the benefit of unused tax loss carryforwards of $826 million (2013 - $322 million) in Canada which start to expire in 2029 and beyond.

As at December 31, 2014, the Company recognized the benefit of unused tax loss carryforwards of $394 million (2013 - $34 million) in the United States which start to expire in 2030 and beyond.

The Company has not provided for deferred income taxes on the difference between the carrying value of substantially all of its foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $4.7 billion (2013 - $2.8 billion). If such earnings are remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Company is subject to potential examinations include the United States (Federal and Texas) and Canada (Federal, Alberta and Ontario). The Company's 2008 and 2010 to 2014 taxation years are still open for audit in the Canadian and United

States jurisdictions. The Company is currently under examination for income tax matters in Canada for the 2011 and 2012 taxation years, and in the United States for the 2008 and 2010 to 2013 taxation years. The Company is not currently under examination for income tax matters in any other jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**46**	54
Gross increases for tax positions of current year	**5**	10
Gross decreases for tax positions of prior years	**-**	(14)
Reduction for lapse of statute of limitations	**(5)**	(4)
Change in translation of foreign currency	**5**	-
Unrecognized tax benefits at end of year	**51**	46

The unrecognized tax benefits as at December 31, 2014, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income tax expense for the year ended December 31, 2014 included nil (2013 - $5 million recovery; 2012 - $1 million expense) of interest and penalties. As at December 31, 2014, interest and penalties of $5 million (2013 - $5 million) have been accrued.

25. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

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 Canadian Plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The United States Plan provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2014 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2014, the mortality assumption was revised for the United States Plan resulting in an increase to pension liabilities of $21 million. In 2013, the mortality assumptions were revised for the Canadian Plans, resulting in an increase to pension liabilities of $58 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2013	December 31, 2014
Gas Distribution	December 31, 2013	December 31, 2016
United States Plan	January 1, 2014	January 1, 2015

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,903**	1,879	**240**	261
Service cost	**108**	103	**8**	9
Interest cost	**93**	79	**12**	11
Employees' contributions	**-**	-	**1**	1
Actuarial (gains)/loss	**411**	(110)	**16**	(40)
Benefits paid	**(75)**	(75)	**(9)**	(7)
Effect of foreign exchange rate changes	**31**	19	**8**	6
Other	**(1)**	8	**-**	(1)
Benefit obligation at end of year	**2,470**	1,903	**276**	240
Change in plan assets				
Fair value of plan assets at beginning of year	**1,799**	1,500	**81**	62
Actual return on plan assets	**179**	200	**7**	8
Employer's contributions	**138**	155	**11**	12
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(75)**	(75)	**(9)**	(7)
Effect of foreign exchange rate changes	**22**	13	**8**	5
Other	**(1)**	6	**-**	-
Fair value of plan assets at end of year[1]	**2,062**	1,799	**99**	81
Underfunded status at end of year	**(408)**	(104)	**(177)**	(159)
Presented as follows:				
Deferred amounts and other assets	**5**	6	**-**	-
Accounts payable and other	**-**	-	**(6)**	(5)
Other long-term liabilities *(Note 17)*	**(413)**	(110)	**(171)**	(154)
	(408)	(104)	**(177)**	(159)

1 *Assets of $32 million (2013 - $27 million) are held by the Company in trust accounts that back non-registered supplemental pension plans benefitting United States plan participants. Due to United States tax regulations, these assets are not restricted from creditors, and therefore the Company is unable to include these balances in plan assets for accounting purposes. However, these assets are committed for the future settlement of non-registered supplemental pension plan obligations included in the underfunded status as at the end of the year.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**4.0%**	5.0%	4.2%	**3.9%**	4.9%	4.0%
Average rate of salary increases	**4.0%**	3.7%	3.7%			

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
(millions of Canadian dollars)						
Benefits earned during the year	**108**	103	84	**8**	9	8
Interest cost on projected benefit obligations	**93**	79	74	**12**	11	10
Expected return on plan assets	**(123)**	(103)	(93)	**(5)**	(4)	(3)
Amortization of prior service costs	**-**	1	2	**-**	-	-
Amortization of actuarial loss	**28**	52	51	**-**	2	2
Net defined benefit costs on an accrual basis	**106**	132	118	**15**	18	17
Defined contribution benefit costs	**4**	4	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**110**	136	122	**15**	18	17
Amount recognized in OCI:						
Net actuarial (gains)/loss[1]	**232**	(158)	42	**15**	(45)	10
Net prior service cost/(credit)[2]	**-**	-	-	**-**	2	-
Total amount recognized in OCI	**232**	(158)	42	**15**	(43)	10
Total amount recognized in Comprehensive income	**342**	(22)	164	**30**	(25)	27

1 *Unamortized actuarial losses included in AOCI, before tax, were $489 million (2013 - $246 million) relating to the pension plans and $26 million (2013 - $11 million) relating to OPEB at December 31, 2014.*

2 *Unamortized prior service costs included in AOCI, before tax, were $6 million (2013 - $6 million) relating to OPEB at December 31, 2014.*

The Company estimates that approximately $28 million related to pension plans and $1 million related to OPEB at December 31, 2014 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*. For the year ended December 31, 2014, an offsetting regulatory liability of $3 million (2013 - $3 million regulatory asset) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**5.0%**	4.2%	4.5%	**4.9%**	4.0%	4.4%
Average rate of return on plan assets	**6.7%**	6.7%	7.1%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.7%	3.5%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.0%	4.4%	2029
Other Medical	4.5%	-	-
United States Plan	7.2%	4.5%	2030

A 1% increase in the assumed medical care trend rate would result in an increase of $37 million in the benefit obligation and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $32 million in the benefit obligation and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
Canadian Plans	**6.7%**	6.6%		
United States Plan	**7.2%**	7.2%	**6.0%**	6.0%

Target Mix for Plan Assets

	Canadian Plans		
	Liquids Pipelines Plan	Gas Distribution Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2014, the pension assets were invested 57.0% (2013 - 58.0%) in equity securities, 32.2% (2013 - 31.0%) in fixed income securities and 10.8% (2013 - 11.0%) in other. The OPEB assets were invested 58.8% (2013 - 59.3%) in equity securities, 40.2% (2013 - 38.3%) in fixed income securities and 1.0% (2013 - 2.4%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $4 million asset (2013 - $1 million asset) and refundable tax assets of $96 million (2013 - $85 million) have been excluded from the table below.

December 31,	2014 Level 1[1]	Level 2[2]	Level 3[3]	Total	2013 Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**42**	**-**	**-**	**42**	42	-	-	42
Fixed income securities								
Canadian government bonds	**121**	**-**	**-**	**121**	99	-	-	99
Corporate bonds and debentures	**4**	**4**	**-**	**8**	3	4	-	7
Canadian corporate bond index fund	**254**	**-**	**-**	**254**	216	-	-	216
Canadian government bond index fund	**198**	**-**	**-**	**198**	167	-	-	167
United States debt index fund	**84**	**-**	**-**	**84**	69	-	-	69
Equity								
Canadian equity securities	**131**	**-**	**-**	**131**	128	-	-	128
United States equity securities	**31**	**-**	**-**	**31**	32	-	-	32
Global equity securities	**11**	**-**	**-**	**11**	11	-	-	11
Canadian equity funds	**255**	**-**	**-**	**255**	216	-	-	216
United States equity funds	**185**	**36**	**-**	**221**	152	33	-	185
Global equity funds	**342**	**134**	**-**	**476**	310	111	-	421
Infrastructure[4]	**-**	**-**	**51**	**51**	-	-	50	50
Real estate[5]	**-**	**-**	**81**	**81**	-	-	76	76
Forward currency contracts	**-**	**(1)**	**-**	**(1)**	-	(6)	-	(6)
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	2	-	-	2
Fixed income securities								
United States government and government agency bonds	**39**	**-**	**-**	**39**	31	-	-	31
Equity								
United States equity funds	**30**	**-**	**-**	**30**	24	-	-	24
Global equity funds	**27**	**-**	**-**	**27**	24	-	-	24

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investments in Bentall Kennedy Prime Canadian Property Fund Ltd. and AEW Core Property Trust are established through the use of valuation models.

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

December 31,	**2014**	2013
(millions of Canadian dollars)		
Balance at beginning of year	**126**	85
Unrealized and realized gains	**26**	7
Purchases and settlements, net	**(20)**	34
Balance at end of year	**132**	126

Plan Contributions by the Company

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Total contributions	**138**	155	**11**	12
Contributions expected to be paid in 2015	**109**		**10**	

Benefits Expected to be Paid by the Company

Year ended December 31,	2015	2016	2017	2018	2019	2020-2024
(millions of Canadian dollars)						
Expected future benefit payments	93	99	106	113	120	720

26. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(400)**	(272)	71
Allowance for equity funds used during construction	**3**	1	1
Interest income on affiliate loans	**20**	23	20
Interest income	**3**	4	7
Noverco preferred shares dividend income	**42**	40	42
Gain on disposition *(Note 6)*	**38**	18	-
OPEB recovery *(Note 5)*	**-**	-	89
Other	**28**	51	8
	(266)	(135)	238

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Accounts receivable and other	**(91)**	(789)	(122)
Accounts receivable from affiliates	**(176)**	(53)	43
Inventory	**(186)**	(315)	42
Deferred amounts and other assets	**(431)**	(25)	(380)
Accounts payable and other	**(829)**	832	(319)
Accounts payable to affiliates	**34**	46	(48)
Interest payable	**24**	25	15
Other long-term liabilities	**(66)**	(130)	109
	(1,721)	(409)	(660)

28. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million for the year ended December 31, 2014 (2013 - $6 million; 2012 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution, Gas Pipelines, Processing and Energy Services and Sponsored Investments segments have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to the Company for transportation services for the year ended December 31, 2014 were $256 million (2013 - $222 million; 2012 - $127 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services made natural gas and NGL purchases of $315 million (2013 - $99 million; 2012 - $15 million) from several joint venture affiliates during the year ended December 31, 2014.

Natural gas sales of $58 million (2013 - $10 million; 2012 - $7 million) were made by certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services to several joint venture affiliates during the year ended December 31, 2014.

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector totalling $183 million (2013 - $181 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates ranging from 4% to 8%.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts that primarily relate to the purchase of services, pipe and other materials, as well as transportation, totalling $15,065 million. The amounts which are expected to be paid in the next five years are $5,965 million, $1,815 million, $1,211 million, $986 million and $966 million, respectively, and $4,122 million thereafter.

Minimum future payments under operating leases for buildings, railcars, storage and pipe are estimated at $1,240 million in aggregate. Estimated annual lease payments for the years ending December 31, 2015 through 2019 are $118 million, $114 million, $104 million, $63 million and $61 million, respectively, and $780 million thereafter. Total rental expense for operating leases, included in Operating and administrative expense, were $91 million, $49 million and $31 million for the years ended December 31, 2014, 2013 and 2012, respectively.

ENBRIDGE ENERGY PARTNERS, L.P.

As at December 31, 2014, Enbridge holds an approximate 33.7% (2013 - 20.6%; 2012 - 21.8%) 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. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

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 EPA which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA.

As of December 31, 2014, regulatory authority transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who 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.

As at December 31, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($193 million after-tax attributable to Enbridge), which is an increase of US$86 million ($12 million after-tax attributable to Enbridge) as compared with December 31, 2013. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. The total cost increase of US$86 million during the year ended December 31, 2014, is primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake and estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2014. 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

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

As at December 31, 2014, the total estimated cost for the Line 6A crude oil release is now approximately US$51 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties, which is an increase of US$3 million (nil after-tax attributable to Enbridge) as compared to December 31, 2013 primarily due to additional legal expenses. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

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 up for renewal and includes commercial liability insurance coverage which 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 December 31, 2014, 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 December 31, 2014, 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, the Company filed a lawsuit against one insurer who is disputing recovery eligibility for Line 6B costs. While the Company believes outstanding claims are covered under the policy, there can be no assurance the Company will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event 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 seven 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, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material.

At December 31, 2014, 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$3.7 million related to civil penalties assessed by the Pipeline and Hazardous Materials Safety Administration (PHMSA), which EEP paid during the third quarter of 2012. The total also included an amount of US$40 million related to civil penalties under the Clean Water Act. 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, emergency response to environmental events. The cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

One claim related to 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, and the parties are currently operating under an agreed interim order.

Lakehead System Line 14 Crude Oil Release
On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the PHMSA on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, EEP received a letter from the PHMSA approving its request to continue the normal operation of Line 14 without pressure restrictions.

The total estimated cost for the repair and remediation associated with the Line 14 crude oil release remains at approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenues and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

AUX SABLE
Notice of Violation
In September 2014, Aux Sable received a Notice of Violation (NOV) from the EPA for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the NOV, Aux Sable discovered what it believes to be additional exceedance of currently permitted limits for Volatile Organic Material. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact, if any, which might result from discussions with the EPA.

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.

30. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

The Company has also agreed to indemnify the Fund for certain liabilities relating to environmental matters arising from operations prior to the transfer of certain crude oil storage assets to the Fund in 2012 and to pay defined payments to the Fund on their investment in Southern Lights in the event shippers do not elect to extend their current contracts post June 2025.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties and affiliates. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities. The Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties and affiliates under these agreements; however, historically, the Company has not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

31. SUBSEQUENT EVENTS

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 $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. However, the Class E units are not entitled to distributions with respect to the quarter ended December 31, 2014. 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. Upon closing of the transaction, Enbridge's economic interest in EEP increased from 33.7% to approximately 37% as a result of the transfer.