Western Union CO
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;">a) Accounts receivable is comprised primarily of customer trade receivables and the natural gas imbalance balance. As such, the fair value of accounts receivable approximates the net carrying value of $1,174 million. The gross amount due is $1,191 million, of which $16 million is not expected to be collected, is included in current assets.

b) The Company has applied the valuation methodologies described in ASC 820, *Fair Value Measurements and Disclosures*, to value the property, plant and equipment purchased. The fair value of Spectra Energy s rate regulated property, plant and equipment is determined, using a market participant perspective, which is their carrying amount. The fair value of the remaining non-regulated property, plant and equipment is determined primarily using variations of the income approach, which is based on the present value of the future after-tax cash flows attributable to each non-regulated asset. Some of the more significant assumptions inherent in the development of the values, from the perspective of a market participant, include, but are not limited to, the amount and timing of projected future cash flows (including revenue and profitability); the discount rate selected to measure the risks inherent in the future cash flows; the assessment of the asset s life cycle; the competitive trends impacting the asset; and customer turnover.

c) Long-term investments represent Spectra Energy s 50% equity investment in DCP Midstream, L.L.C., Gulfstream Natural Gas System, L.L.C., NEXUS Gas System Transmission L.L.C., Steckman Ridge LP, Islander East Pipeline Company, L.L.C., Southeast Supply Header L.L.C., and 10% equity interest in Penn East Pipeline Company L.L.C. The fair value of these investments is determined using an income approach.

d) Fair value of the long-term debt is determined based on the current underlying Government of Canada and United States Treasury interest rates on the corresponding bonds, as well as an implied credit spread based on current market conditions. The fair value adjustment to long-term debt related to rate-regulated entities of $629 million also results in a regulatory offset in deferred amounts and other assets.

e) Intangible assets consist of customer relationships in the non-regulated business, which represent the underlying relationship from long term agreements with customers that are capitalized upon acquisition, determined using the income approach. Intangible assets are amortized on a straight-line basis over their expected lives.

f) The fair value of Spectra Energy s noncontrolling interest includes approximately 78.4 million Spectra Energy Partners, LP common units outstanding to the public, valued at the February 24, 2017 closing price of US$44.88 per common units on the New York Stock Exchange, and units held by third parties in Maritimes and Northeast Pipeline, Sabal Trail Transmission, L.L.C. and Algonquin Gas Transmission, L.L.C., valued based on the underlying net assets of each reporting unit, and preferred stock held by third parties in Union Gas Limited and Westcoast Energy Inc.

g) The Company recorded $34.7 billion in goodwill related to this transaction which is primarily related to expected synergies from the transaction. The goodwill balance recognized is not deductible for tax purposes. Factors that contributed to the goodwill include the opportunity to expand Enbridge s natural gas pipelines segment, the potential for cost and supply chain optimization synergies, existing assembled assets and work force that cannot be duplicated at the same cost by a new entrant, franchise rights and other intangibles not separately identifiable because they are inextricably linked to the provision of regulated utility service and the enhanced scale and geographic diversity which provide greater optionality and platforms for future growth.

Acquisition-related expenses incurred to date were approximately $203 million. Costs incurred for the three months ended March 31, 2017 of $152 million (six months ended December 31, 2017 - $51 million) are included in Operating and administrative expenses in the Consolidated Statements of Earnings.

For the nine months ending December 31, 2017 and for the years ending December 31, 2018 through 2021, the Company has future minimum lease payment commitments for operating leases of $39 million, $51 million, $51 million, $45 million, $41 million respectively, and $201 million thereafter, as a result of the Merger Transaction.

Upon completion of the Merger Transaction, the Company began consolidating Spectra Energy.

Since the closing date through March 31, 2017, Spectra Energy has generated approximately $736 million in revenues and $32 million in earnings.

The following supplemental pro forma consolidated financial information of the Company for the quarters ended March 31, 2017 and 2016 includes the results of operations for Spectra Energy as if the Merger Transaction had been completed on January 1, 2016.

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars, except per share amounts)		
Revenues	**12,437**	10,662
Earnings attributable to Enbridge Inc. common shareholders[1]	**991**	1,556

1 Merger Transaction costs of $152 million (after-tax $111 million) were excluded from earnings for the three months ended March 31, 2017.

Bakken Pipeline System

On February 15, 2017, Enbridge Energy Partners, L.P. (EEP) completed the acquisition of an effective 27.6% interest in the Bakken Pipeline System for a purchase price of $1.96 billion (US$1.5 billion). The Bakken Pipeline System connects the prolific Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost.

The purchase price was allocated as follows:

February 15,	2017
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	75
Property, plant and equipment	2,107
Intangible assets	716
Goodwill	19
Current liabilities	(116)
Other long-term liabilities	(838)
	1,963
Purchase price:	
Cash	1,963

The Company s interest in the Bakken Pipeline System is accounted for under the equity method of accounting. For the three months ended March 31, 2017, no equity earnings were recognized as the Bakken Pipeline System has not been placed into service.

The Company s equity investment includes 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 $19 million in goodwill and $1,219 million in amortizable assets included within the Liquids Pipelines segment.

Hohe See Offshore Wind Project

Effective February 8, 2017, Enbridge acquired an effective 50% interest in EnBW Hohe See GmbH & Co. KG (HoHe See), a German offshore wind development company. HoHe See is co-owned by Enbridge and Energie Baden-Wurttenberg AG, a major German electric utility. Construction of the wind farm began in March 2017 and it is expected to be fully operational in late 2019. Enbridge s portion of the costs incurred to date is approximately $415 million (291 million) presented in Long-term investments and included within the Green Power and Transmission segment.

DISPOSITION

Ozark Pipeline

On March 1, 2017, the Company completed the sale of the Ozark Pipeline assets to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$219 million), including reimbursement of certain costs up to the closing date of the transaction. A gain on sale of $14 million before tax was recognized in Other income/(expense) on the Consolidated Statements of Earnings. The Ozark Pipeline assets were included within the Company s Liquids Pipelines segment.

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5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain EEP subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis, 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$275 million ($366 million) and US$355 million ($477 million) as at March 31, 2017 and December 31, 2016, respectively.

On April 28, 2017, in conjunction with the United States Sponsored Vehicle Strategy (*Note 16*), EEP terminated the Receivables Agreement with the Enbridge wholly-owned SPE in exchange for a one-time US$5 million ($7 million) payment to EEP.

6. VARIABLE INTEREST ENTITIES

In connection with the acquisition of Spectra Energy *(Note 4)*, the Company has acquired both consolidated and unconsolidated variable interest entities (VIEs).

ACQUIRED CONSOLIDATED VARIABLE INTEREST ENTITIES

Spectra Energy Partners, L.P.

The Company acquired a 75% ownership in Spectra Energy Partners, L.P. (SEP) through the Merger Transaction. SEP is a natural gas and crude oil infrastructure master limited partnership and is considered a VIE as its limited partners do not have substantive kick-out rights or participating rights. The Company is the primary beneficiary because it has the power to direct SEP s activities that have a significant impact on SEP s economic performance.

Valley Crossing Pipeline, LLC

Valley Crossing Pipeline, LLC (Valley Crossing), a wholly-owned subsidiary, is constructing a natural gas pipeline to transport natural gas within Texas. The current estimate of the total remaining construction cost is approximately $1.6 billion (US$1.2 billion). Valley Crossing is a VIE due to insufficient equity at risk to finance its activities. The Company is the primary beneficiary because it directs the activities of Valley Crossing that most significantly impact its economic performance.

Other Limited Partnerships

By virtue of a lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly-owned or majority owned by Enbridge and/or its subsidiaries, acquired through the Merger Transaction, are considered acquired VIEs. As these entities are wholly-owned or majority owned and directed by Enbridge with no third parties having the ability to direct any of the significant activities, the Company is considered the primary beneficiary.

The following table includes assets to be used to settle liabilities of Enbridge s acquired consolidated VIEs and liabilities of Enbridge s acquired consolidated VIEs for which creditors do not have recourse to the Company s general credit as the primary beneficiary. These acquired assets and liabilities are included in the Consolidated Statements of Financial Position.

March 31,	2017
(millions of Canadian dollars)	
Assets	
Cash and cash equivalents	**720**
Accounts receivable and other	**1,385**
Inventory	**144**
	2,249
Property, plant and equipment, net	**30,237**
Long-term investments	**1,595**
Restricted long-term investments	**103**
Deferred amounts and other assets	**1,177**
Intangible assets, net	**107**
	35,468
Liabilities	
Short-term borrowings	**435**
Accounts payable and other	**1,748**
Interest payable	**105**
Current maturities of long-term debt	**727**
	3,015
Long-term debt	**13,036**
Other long-term liabilities	**1,371**
Deferred income taxes	**691**
	18,113
Net assets before noncontrolling interests	**17,355**

ACQUIRED UNCONSOLIDATED VARIABLE INTEREST ENTITIES

The following unconsolidated VIEs are included within Long-term investments in the table above.

Nexus Gas Transmission, LLC

SEP owns a 50% equity investment in Nexus Gas Transmission, LLC (Nexus), a joint venture that is constructing a natural gas pipeline from Ohio to Michigan and continuing on to Ontario, Canada. Nexus is a VIE due to insufficient equity at risk to finance its activities. The Company is not the primary beneficiary since the power to direct the activities of Nexus that most significantly impact its economic performance is shared. Nexus has a carrying value of $580 million (US$435 million) at March 31, 2017 and the Company s maximum exposure to loss is $1,358 million (US$1,019 million).

PennEast Pipeline Company, LLC

SEP owns a 10% cost investment in PennEast Pipeline Company, LLC (PennEast). PennEast is constructing a natural gas pipeline from northeastern Pennsylvania to New Jersey. PennEast is a VIE due to insufficient equity at risk to finance its activities. The Company is not the primary beneficiary since it does not have the power to direct the activities of PennEast that most significantly impact its economic performance. PennEast has a carrying value of $20 million (US$15 million) and the Company s maximum exposure to loss is $183 million (US$137 million).

7. DEBT

The following table provides details of the Company s committed credit facilities as at March 31, 2017 and December 31, 2016.

		March 31, 2017			December 31, 2016
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Inc.	2017-2022	**8,416**	**5,785**	**2,631**	8,183
Enbridge (U.S.) Inc.	2018-2019	**3,903**	**554**	**3,349**	3,934
Enbridge Energy Partners, L.P.	2018-2020	**3,497**	**3,119**	**378**	3,525
Enbridge Gas Distribution Inc.	2018-2019	**1,017**	**407**	**610**	1,017
Enbridge Income Fund	2019	**1,500**	**446**	**1,054**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**27**	**-**	**27**	27
Enbridge Pipelines Inc.	2018	**3,000**	**1,138**	**1,862**	3,000
Enbridge Southern Lights LP	2018	**5**	**-**	**5**	5
Midcoast Energy Partners, L.P.	2018	**893**	**586**	**307**	900
Spectra Energy Capital, LLC[2]	2018-2021	**1,732**	**1,051**	**681**	-
Spectra Energy Partners[2]	2018-2021	**3,863**	**1,934**	**1,929**	-
Westcoast Energy Inc. [2]	2021	**400**	**-**	**400**	-
Union Gas Limited[2]	2021	**700**	**435**	**265**	-
Total committed credit facilities		**28,953**	**15,455**	**13,498**	22,091

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

2 These facilities were acquired on February 27, 2017 in conjunction with the Merger Transaction (Note 4).

During the three months ended March 31, 2017, the Company established a five-year, term credit facility for $239 million (¥20,000 million) with a syndicate of Japanese banks.

In addition to the committed credit facilities noted above, the Company also has $566 million (December 31, 2016 - $335 million) of uncommitted demand credit facilities, of which $171 million (December 31, 2016 - $177 million) were unutilized as at March 31, 2017.

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 2017 to 2022.

As at March 31, 2017, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $13,015 million (December 31, 2016 - $7,344 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

As noted in Note 4, as a result of the Merger Transaction, the debt of the Company increased by $22,978 million on the acquisition date. Accordingly, annual debt repayment amounts have also increased. For the nine months ending December 31, 2017 and for the years ending December 31, 2018 through 2021, the Company s debenture, term note and non-revolving credit facility maturities are $4,314 million, $4,216 million, $4,114 million, $4,082 million, $2,831 million respectively, and $33,768 million thereafter.

The Company s debentures and term notes bear interest at fixed rates and interest obligations for the nine months ending December 31, 2017 and for the years ending December 31, 2018 through 2021 are $1,815 million, $2,231 million, $2,032 million, $1,835 million and $1,669 million, respectively.

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The Company has the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

8. SHARE CAPITAL

COMMON SHARES

March 31, (millions of Canadian dollars; number of common shares in millions)	**2017** Number of Shares	**2017** Amount	2016 Number of Shares	2016 Amount
Balance at beginning of period	**943**	**10,492**	868	7,391
Common shares issued[1]	**-**	**-**	56	2,241
Common shares issued in Merger Transaction[2]	**691**	**37,428**	-	-
Dividend Reinvestment and Share Purchase Plan	**4**	**194**	4	184
Shares issued on exercise of stock options	**1**	**33**	1	12
	1,639	**48,147**	929	9,828

1 2016 - Gross proceeds $2,300 million; net issuance costs $59 million.

2 Common shares valued at $37,429 million were issued in the Merger Transaction (Note 4); net issuance costs were $1 million.

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 13 million (2016 - 12 million) for the three months ended March 31, 2017, resulting from the Company s reciprocal investment in Noverco Inc.

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

(number of common shares in millions)	Three months ended March 31, **2017**	2016
Weighted average shares outstanding	**1,177**	876
Effect of dilutive options	**10**	6
Diluted weighted average shares outstanding	**1,187**	882

For the three months ended March 31, 2017, 13,545,193 anti-dilutive stock options (2016 - 20,150,772) with a weighted average exercise price of $57.71 (2016 - $49.62) were excluded from the diluted earnings per common share calculation.

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9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income/(loss) (AOCI) attributable to Enbridge Inc. common shareholders for the three months ended March 31, 2017 and 2016 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, 2017	**(746)**	**(629)**	**2,700**	**37**	**(304)**	**1,058**
Other comprehensive income/(loss) retained in AOCI	**(1)**	**50**	**293**	**5**	**-**	**347**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	**31**	**-**	**-**	**-**	**-**	**31**
Commodity contracts2	**(2)**	**-**	**-**	**-**	**-**	**(2)**
Foreign exchange contracts3	**-**	**-**	**-**	**-**	**-**	**-**
Other contracts4	**9**	**-**	**-**	**-**	**-**	**9**
Amortization of pension and OPEB actuarial loss and prior service cost5	**-**	**-**	**-**	**-**	**6**	**6**
	37	**50**	**293**	**5**	**6**	**391**
Tax impact						
Income tax on amounts retained in AOCI	**(1)**	**(1)**	**-**	**1**	**-**	**(1)**
Income tax on amounts reclassified to earnings	**(8)**	**-**	**-**	**-**	**(2)**	**(10)**
	(9)	**(1)**	**-**	**1**	**(2)**	**(11)**
Balance at March 31, 2017	**(718)**	**(580)**	**2,993**	**43**	**(300)**	**1,438**

	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, 2016	(688)	(795)	3,365	37	(287)	1,632
Other comprehensive income/(loss) retained in AOCI	(459)	409	(1,314)	(8)	-	(1,372)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	29	-	-	-	-	29
Commodity contracts2	(3)	-	-	-	-	(3)
Foreign exchange contracts3	2	-	-	-	-	2
Other contracts4	(26)	-	-	-	-	(26)
Amortization of pension and OPEB actuarial loss and prior service cost5	-	-	-	-	3	3
	(457)	409	(1,314)	(8)	3	(1,367)
Tax impact						
Income tax on amounts retained in AOCI	118	(15)	-	6	-	109
Income tax on amounts reclassified to earnings	(7)	-	-	-	(1)	(8)
	111	(15)	-	6	(1)	101
Balance at March 31, 2016	(1,034)	(401)	2,051	35	(285)	366

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 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.

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10. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company s earnings, cash flows and other comprehensive income (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 and pay floating-receive fixed 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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.4% and fixed to floating 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 via execution of floating to fixed interest rate swaps with an average swap rate of 3.7%.

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of its ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and natural gas liquids (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.

Emission Allowance Price Risk

Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that the gas distribution business of the Company is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations. Similar to the gas supply procurement framework, the Ontario Energy Board s (OEB) framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

Equity Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company s derivative instruments.

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

March 31, 2017	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value 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							
Foreign exchange contracts	**98**	**3**	**-**	**5**	**106**	**(104)**	**2**
Interest rate contracts	**4**	**-**	**-**	**-**	**4**	**(4)**	**-**
Commodity contracts	**11**	**-**	**-**	**229**	**240**	**(61)**	**179**
	113	**3**	**-**	**234**	**350**	**(169)**	**181**
Deferred amounts and other assets							
Foreign exchange contracts	**9**	**2**	**-**	**67**	**78**	**(78)**	**-**
Interest rate contracts	**7**	**-**	**12**	**-**	**19**	**(5)**	**14**
Commodity contracts	**26**	**-**	**-**	**48**	**74**	**(34)**	**40**
Other contracts	**1**	**-**	**-**	**1**	**2**	**-**	**2**
	43	**2**	**12**	**116**	**173**	**(117)**	**56**
Accounts payable and other							
Foreign exchange contracts	**(5)**	**(290)**	**-**	**(680)**	**(975)**	**104**	**(871)**
Interest rate contracts	**(442)**	**-**	**-**	**(144)**	**(586)**	**4**	**(582)**
Commodity contracts	**-**	**-**	**-**	**(194)**	**(194)**	**61**	**(133)**
Other contracts	**(1)**	**-**	**-**	**(3)**	**(4)**	**-**	**(4)**
	(448)	**(290)**	**-**	**(1,021)**	**(1,759)**	**169**	**(1,590)**
Other long-term liabilities							
Foreign exchange contracts	**(1)**	**(37)**	**-**	**(1,733)**	**(1,771)**	**78**	**(1,693)**
Interest rate contracts	**(275)**	**-**	**(1)**	**(210)**	**(486)**	**5**	**(481)**
Commodity contracts	**-**	**-**	**-**	**(197)**	**(197)**	**34**	**(163)**
	(276)	**(37)**	**(1)**	**(2,140)**	**(2,454)**	**117**	**(2,337)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**101**	**(322)**	**-**	**(2,341)**	**(2,562)**	**-**	**(2,562)**
Interest rate contracts	**(706)**	**-**	**11**	**(354)**	**(1,049)**	**-**	**(1,049)**
Commodity contracts	**37**	**-**	**-**	**(114)**	**(77)**	**-**	**(77)**
Other contracts	**-**	**-**	**-**	**(2)**	**(2)**	**-**	**(2)**
	(568)	**(322)**	**11**	**(2,811)**	**(3,690)**	**-**	**(3,690)**

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December 31, 2016	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						
Foreign exchange contracts	101	3	5	109	(103)	6
Interest rate contracts	3	-	-	3	(3)	-
Commodity contracts	9	-	232	241	(125)	116
	113	3	237	353	(231)	122
Deferred amounts and other assets						
Foreign exchange contracts	1	3	69	73	(72)	1
Interest rate contracts	8	-	-	8	(6)	2
Commodity contracts	7	-	61	68	(22)	46
Other contracts	1	-	1	2	-	2
	17	3	131	151	(100)	51
Accounts payable and other						
Foreign exchange contracts	-	(268)	(727)	(995)	103	(892)
Interest rate contracts	(452)	-	(131)	(583)	3	(580)
Commodity contracts	-	-	(359)	(359)	125	(234)
Other contracts	(1)	-	(3)	(4)	-	(4)
	(453)	(268)	(1,220)	(1,941)	231	(1,710)
Other long-term liabilities						
Foreign exchange contracts	-	(68)	(1,961)	(2,029)	72	(1,957)
Interest rate contracts	(268)	-	(205)	(473)	6	(467)
Commodity contracts	-	-	(211)	(211)	22	(189)
	(268)	(68)	(2,377)	(2,713)	100	2,613
Total net derivative asset/(liability)						
Foreign exchange contracts	102	(330)	(2,614)	(2,842)	-	(2,842)
Interest rate contracts	(709)	-	(336)	(1,045)	-	(1,045)
Commodity contracts	16	-	(277)	(261)	-	(261)
Other contracts	-	-	(2)	(2)	-	(2)
	(591)	(330)	(3,229)	(4,150)	-	(4,150)

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

March 31, 2017	2017	2018	2019	2020	2021	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**1,069**	**2**	**2**	**2**	**-**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**3,911**	**2,770**	**2,945**	**2,723**	**567**	**224**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**89**	**6**	**-**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**89**	**25**	**27**	**144**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**149**	**256**	**340**	**-**	**-**	**-**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**-**	**-**	**-**	**35**	**152**	**952**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**-**	**-**	**32,662**	**-**	**-**	**20,000**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**4,828**	**5,137**	**1,571**	**152**	**100**	**299**
Interest rate contracts - long-term receive fixed rate *(millions of Canadian dollars)*	**1,390**	**1,302**	**900**	**671**	**345**	**320**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**3,982**	**2,736**	**767**	**-**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**48**	**40**	**-**	**-**	**-**	**-**

Commodity contracts - natural gas *(billions of cubic feet)*	**(111)**	**(26)**	**20**	**-**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**4**	**(9)**	**-**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(3)**	**(8)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**42**	**30**	**31**	**35**	**(3)**	**(43)**

21

December 31, 2016	2017	2018	2019	2020	2021	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	991	2	2	2	-	-
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	4,369	2,768	2,943	2,722	566	223
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	91	6	-	-	-	-
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	-	-	89	25	27	144
Foreign exchange contracts - Japanese yen forwards - purchase (*millions of yen*)	-	-	32,662	-	-	-
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	6,713	5,161	1,581	153	100	300
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	3,998	2,743	768	-	-	-
Equity contracts *(millions of Canadian dollars)*	48	40	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	(93)	(42)	(17)	(9)	-	-
Commodity contracts - crude oil *(millions of barrels)*	(11)	(9)	-	-	-	-
Commodity contracts - NGL *(millions of barrels)*	(8)	(6)	-	-	-	-
Commodity contracts - power *(MWH)*	40	30	31	35	(3)	(43)

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

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

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(2)**	(35)
Interest rate contracts	**(14)**	(576)
Commodity contracts	**21**	16
Other contracts	**(9)**	31
Net investment hedges		
Foreign exchange contracts	**8**	84
	4	(480)
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*		
Foreign exchange contracts1	**1**	3
Interest rate contracts2	**48**	(21)
Commodity contracts3	**(2)**	(8)
Other contracts4	**9**	(26)
	56	(52)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts2	**2**	26
	2	26

1 *Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3

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

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

The Company estimates that a gain of $19 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 33 months as at March 31, 2017.

Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense on the Consolidated Statements of Earnings. During the three months ended March 31, 2017, the Company recognized an unrealized loss of $2 million (2016 - nil) on the derivative and an unrealized gain of $2 million (2016 - nil) on the hedged item in net income. The difference in the amounts, if any, represents hedge ineffectiveness.

Non-Qualifying Derivatives

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

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Foreign exchange contracts1	**273**	1,016
Interest rate contracts2	**(18)**	4
Commodity contracts3	**163**	(184)
Other contracts4	**-**	6
Total unrealized derivative fair value gain/(loss), net	**418**	842

1 Reported within Transportation and other services revenues (2017 - $159 million gain; 2016 - $582 million gain) and Other income/(expense) (2017 - $114 million gain; 2016 - $434 million gain) in the Consolidated Statements of Earnings.

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

3 Reported within Transportation and other services revenues (2017 - $22 million loss; 2016 - $39 million gain), Commodity sales (2017 - $187 million gain; 2016 - $285 million loss), Commodity costs (2017 - $5 million gain; 2016 - $76 million gain) and Operating and administrative expense (2017 - $7 million loss; 2016 - 14 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 that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintains substantial capacity under its committed bank lines of credit to address any contingencies. 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 also 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 deemed to be in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2017. 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, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

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

	March 31, 2017	December 31, 2016
(millions of Canadian dollars)		
Canadian financial institutions	**39**	39
United States financial institutions	**158**	179
European financial institutions	**91**	106
Asian financial institutions	**1**	1
Other[1]	**161**	162
	450	487

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

As at March 31, 2017, the Company had provided letters of credit totalling $167 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held no cash collateral on derivative asset exposures as at March 31, 2017 and December 31, 2016.

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 and Union Gas, credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

Level 3

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

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

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

March 31, 2017	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**106**	**-**	**106**
Interest rate contracts	**-**	**4**	**-**	**4**
Commodity contracts	**8**	**75**	**157**	**240**
	8	**185**	**157**	**350**
Long-term derivative assets				
Foreign exchange contracts	**-**	**78**	**-**	**78**
Interest rate contracts	**-**	**19**	**-**	**19**
Commodity contracts	**-**	**23**	**51**	**74**
Other contracts	**-**	**2**	**-**	**2**
	-	**122**	**51**	**173**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(975)**	**-**	**(975)**
Interest rate contracts	**-**	**(586)**	**-**	**(586)**
Commodity contracts	**(5)**	**(44)**	**(145)**	**(194)**
Other contracts	**-**	**(4)**	**-**	**(4)**
	(5)	**(1,609)**	**(145)**	**(1,759)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(1,771)**	**-**	**(1,771)**
Interest rate contracts	**-**	**(486)**	**-**	**(486)**
Commodity contracts	**-**	**(11)**	**(186)**	**(197)**
	-	**(2,268)**	**(186)**	**(2,454)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,562)**	**-**	**(2,562)**
Interest rate contracts	**-**	**(1,049)**	**-**	**(1,049)**
Commodity contracts	**3**	**43**	**(123)**	**(77)**
Other contracts	**-**	**(2)**	**-**	**(2)**
	3	**(3,570)**	**(123)**	**(3,690)**

December 31, 2016		Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)					
Financial assets					
Current derivative assets					
	Foreign exchange contracts	-	109	-	109
	Interest rate contracts	-	3	-	3
	Commodity contracts	2	86	153	241
		2	198	153	353
Long-term derivative assets					
	Foreign exchange contracts	-	73	-	73
	Interest rate contracts	-	8	-	8
	Commodity contracts	-	43	25	68
	Other contracts	-	2	-	2
		-	126	25	151
Financial liabilities					
Current derivative liabilities					
	Foreign exchange contracts	-	(995)	-	(995)
	Interest rate contracts	-	(583)	-	(583)
	Commodity contracts	(12)	(75)	(272)	(359)
	Other contracts	-	(4)	-	(4)
		(12)	(1,657)	(272)	(1,941)
Long-term derivative liabilities					
	Foreign exchange contracts	-	(2,029)	-	(2,029)
	Interest rate contracts	-	(473)	-	(473)
	Commodity contracts	-	(10)	(201)	(211)
		-	(2,512)	(201)	(2,713)
Total net financial asset/(liability)					
	Foreign exchange contracts	-	(2,842)	-	(2,842)
	Interest rate contracts	-	(1,045)	-	(1,045)
	Commodity contracts	(10)	44	(295)	(261)
	Other contracts	-	(2)	-	(2)
		(10)	(3,845)	(295)	(4,150)

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

March 31, 2017	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial1						
Natural gas	20	Forward gas price	3.07	4.91	3.62	$/mmbtu3
NGL	(10)	Forward NGL price	0.31	1.53	1.13	$/gallon
Power	(145)	Forward power price	18.50	63.70	42.61	$/MWH
Commodity contracts - physical1						
Natural gas	(41)	Forward gas price	2.62	7.34	3.29	$/mmbtu3
Crude	46	Forward crude price	40.97	75.64	33.34	$/barrel
NGL	6	Forward NGL price	0.30	1.72	1.05	$/gallon
Commodity options2						
Crude, NGL	-	Option volatility	22%	100%	49%	
Power	1	Option volatility	23%	50%	24%	
	(123)					

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, 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:

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**(295)**	54
Total gains/(loss)		
Included in earnings[1]	**83**	(40)
Included in OCI	**19**	7
Settlements	**70**	(123)
Level 3 net derivative liability at end of period	**(123)**	(102)

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 March 31, 2017 or 2016.

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 $110 million as at March 31, 2017 (December 31, 2016 - $110 million).

The Company has Restricted long-term investments held in trust totalling $243 million as at March 31, 2017 (December 31, 2016 - $90 million) which are recognized at fair value.

The Company has a held to maturity preferred share investment carried at its amortized cost of $388 million as at March 31, 2017 (December 31, 2016 - $355 million). These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.38%. As at March 31, 2017, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2016 - $580 million).

As at March 31, 2017, the Company s long-term debt had a carrying value of $65,336 million (December 31, 2016 - $40,761 million) before debt issuance cost and a fair value of $68,603 million (December 31, 2016 - $43,910 million). The Company also has noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets. As at March 31, 2017, the noncurrent notes receivable has a carrying value of $95 million (December 31, 2016 - nil) and a fair value of $95 million (December 31, 2016 - nil).

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 three months ended March 31, 2017, the Company recognized an unrealized foreign exchange gain on the translation of United States dollar denominated debt of $20 million (2016 - unrealized gain of $297 million) and an unrealized gain on the change in fair value of its outstanding foreign exchange forward contracts of $9 million (2016 - $84 million) in OCI. The Company recognized a realized gain of $1 million (2016 - nil) in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized gain of $20 million (2016 - $28 million) in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the three months ended March 31, 2017 (2016 - nil).

11. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2017 was 17.3% (2016 - 23.6%). The lower effective tax rate in 2017 was attributable to the rate-regulated tax benefit and other permanent items relative to the earnings in the first three months of 2017.

12. RETIREMENT AND POSTRETIREMENT BENEFITS

NET BENEFIT COSTS RECOGNIZED

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Benefits earned during the period	**54**	42
Interest cost on projected benefit obligations	**32**	26
Expected return on plan assets	**(51)**	(38)
Amortization of actuarial loss	**9**	9
Net benefit costs on an accrual basis[1,2]	**44**	39

1 *Included in net benefit costs for the three months ended March 31, 2017 are costs related to OPEB of $5 million (2016 - $4 million).*
2 *For the three months ended March 31, 2017, offsetting regulatory liabilities of nil (2016 - $2 million) have been recorded to the extent pension and OPEB costs are expected to be refunded to, or collected from, customers in future rates.*

ACQUIRED PENSION PLANS

In connection with the acquisition of Spectra Energy (Note 4), the Company has assumed registered and non-registered pension plans in both Canada and the United States (the Canadian Plans and United States Plans, respectively), which provide either defined benefit or defined contribution pension benefits to employees of the Company.

The acquired Canadian Plans provide registered and non-registered, contributory and non-contributory defined benefit plans and defined contribution retirement plans covering substantially all Canadian employees of Spectra Energy. The Canadian defined benefit plans provide retirement benefits based on each plan participant s years of service and final average earnings. Under the Canadian defined contribution plan, company contributions are determined according to the terms of the plan and based on each plan participant s age, years of service and current eligible earnings. The Company also provides non-qualified defined benefit supplemental pensions to all employees who retire under a defined benefit registered pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada).

The acquired United States Plans provides Company funded defined benefit pension benefits for United States based employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage of current eligible earnings and current interest credits. The Company also has non-qualified, non-contributory; unfunded defined benefit plans which cover certain current and former executives based in the United States. These non-Qualified Pension Plans have no plan assets. There are other non-qualified plans such as savings and deferred compensation plans which cover certain current and former executives based in the United States.

A measurement date of February 27, 2017 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States plans.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health care and life insurance coverage for qualifying retired employees on a contributory and non-contributory basis.

The following is a summary of the fair value of the pension and OPEB-related balances assumed as at the February 27, 2017 acquisition date:

	Pension		OPEB	
As at February 27, 2017	U.S.	Canada	U.S.	Canada
(millions of Canadian dollars)				
Accrued benefit obligation and plan assets assumed				
Projected benefit obligation	818	1,505	275	146
Fair value of plan assets	737	1,290	103	-
Underfunded status at end of year	(81)	(215)	(172)	(146)
Presented as follows:				
Deferred amounts and other assets	-	23	-	-
Accounts payable and other	(2)	-	(3)	(4)
Other long-term liabilities	(79)	(238)	(169)	(142)
	(81)	(215)	(172)	(146)

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

	Pension		OPEB	
As at February 27, 2017	U.S.	Canada	U.S.	Canada
Discount rate	3.6%	3.8%	3.5%	3.9%
Average rate of salary increases	4.0%	3.0%		

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	5%	5%	
United States Plan	7.5%	4.5%	2037

PLAN ASSETS

Pension plan assets are maintained in master trusts in both the United States and Canada. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets are set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. Actual asset allocation of investments is regularly reviewed and periodically rebalanced to the targeted allocation when considered appropriate.

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

As at February 27, 2017	Pension	OPEB
Canadian Plans	6.4%	
United States Plan	5.5%	4.8%

Target Mix for Plan Assets

	Canadian Plans	United States Plans
Equity securities	55.0%	30.0%
Fixed income securities	45.0%	60.0%
Other	0.0%	10.0%

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 February 27, 2017, the pension assets were invested 48.9% in equity securities, 46.7% in fixed income securities and 4.4% in other. The OPEB assets were invested 38.8% in equity securities, 47.6% in fixed income securities and 13.6% in other.

As at February 27, 2017 *(millions of Canadian dollars)*	Level 1[1]	Level 2[2]	Level 3[3]	Total
Pension				
Cash and cash equivalents	4	-	-	4
Fixed income securities	946	-	-	946
Equity	580	412	-	992
Other	-	-	85	85
OPEB				
Cash and cash equivalents	6	-	-	6
Fixed income securities	37	12	-	49
Equity	21	19	-	40
Other	-	-	8	8

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.

PLAN CONTRIBUTIONS BY THE COMPANY

Year ended December 31, *(millions of Canadian dollars)*	Pension	OPEB
Contributions expected to be paid in 2017	25	8

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2017	2018	2019	2020	2021	2022-2026
(millions of Canadian dollars)						
Expected future benefit payments	124	150	151	157	153	820

13. SEVERANCE COSTS

Included in Operating and administrative is $104 million (2016 - nil) for severance costs related to termination benefits to employees. This resulted from an enterprise-wide reduction of workforce that occurred in March 2017 following the completion of the Merger Transaction. Substantially all of the amounts are included within Eliminations and Other.

Of the total severance costs incurred in 2017, $4 million was paid at March 31, 2017 with the remaining $100 million included in Accounts payable and other as at March 31, 2017.

14. 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.

The following denotes related party transactions and their impact on earnings during the period from the acquisition date of February 27, 2016 to March 31, 2017 for Spectra Energy, acquired in the Merger Transaction.

DCP Midstream, a joint venture, processes certain of the Company s pipeline customers gas to meet gas quality specifications in order to be transported on the Company s Texas Eastern Transmission, LP system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to the Company. As a result, the Company received $7 million (US$5 million) classified as revenue from Transportation and other services in the Company s Consolidated Statement of Earnings.

Spectra Energy provides certain administrative and other services to certain operating entities and recorded recoveries of costs from these affiliates of $19 million (US$14 million). Cost recoveries are classified as a reduction to Operating and Administrative costs in the Consolidated Statements of Earnings. Outstanding receivables from these affiliates totalled $25 million (US$19 million) at March 31, 2017.

15. CONTINGENCIES

LAKEHEAD SYSTEM LINES 6A AND LINE 6B CRUDE OIL RELEASE

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP s Lakehead Pipeline System (Lakehead System) was reported near Marshall, Michigan.

As at March 31, 2017, EEP s total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge) including those costs that were considered probable and that could be reasonably estimated at March 31, 2017. Despite the efforts EEP has made to ensure the reasonableness of its estimate, 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.

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 has completed the cleanup, remediation and restoration of the areas affected by the release. The total estimated cost for the Line 6A crude oil release was approximately US$53 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at March 31, 2017, EEP has no remaining estimated liability.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. As at December 31, 2016, 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 applicable limit. Of the remaining US$103 million coverage limit, US$85 million was the subject matter of a lawsuit against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. On May 2, 2017 the arbitration panel issued a decision that was not favourable to Enbridge. As a result, EEP is unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

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

Line 6A and 6B Fines and Penalties

As at March 31, 2017, included in EEP s total estimated costs related to the Line 6B crude oil release were US$69 million in fines and penalties. Of this amount, US$62 million relates to civil penalties under the Clean Water Act of the United States, which EEP fully accrued but has not paid, pending approval of the Consent Decree, as described below.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan Southern Division (the Court). The Consent Decree is EEP s signed settlement agreement with the United States Environmental Protection Agency (EPA) and the United States Department of Justice regarding the Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, EEP will pay US$62 million in civil penalties: US$61 million in respect of Line 6B and US$1 million in respect of Line 6A. Subsequent to filing the Consent Decree, the Department of Justice received public comments on the contents of the Consent Decree and with EEP s concurrence made certain modifications to the document to address some of these comments before filing an amended Consent Decree on January 19, 2017. The Consent Decree will take effect upon approval by the Court.

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.

16. SUBSEQUENT EVENTS

UNITED STATES SPONSORED VEHICLE STRATEGY

On April 28, 2017, Enbridge announced the completion of the strategic review of EEP. The following actions, together with the measures announced in January 2017 and disclosed in the Company s annual consolidated financial statements for 2016, were taken:

Acquisition of Midcoast Assets

Enbridge, through its wholly owned subsidiary, entered into a definitive agreement with EEP to acquire all of EEP s interest in the Midcoast gas gathering and processing business (Midcoast) for cash consideration of US$1.31 billion plus existing indebtedness of Midcoast Energy Partners, L.P. (MEP) of US$0.84 billion. Subsequent to the closing of the previously announced privatization of MEP, which also closed on April 27, 2017, as discussed below, 100 percent of the Midcoast business will be owned by Enbridge.

Finalization of Bakken Pipeline System Joint Funding Agreement

Enbridge entered into a joint funding arrangement with EEP for the Bakken Pipeline System, whereby Enbridge owns 75% and EEP owns 25% of the Bakken Pipeline System. EEP will have a five-year option to increase its interest by 20% at net book value. With the finalization of this joint funding arrangement, EEP repaid the outstanding balance of US$1.5 billion under a credit agreement with Enbridge which it had drawn upon to fund the initial purchase.

EEP Strategic Restructuring Actions

EEP redeemed all of its outstanding Series 1 Preferred Units held by Enbridge at face value of US$1.2 billion through the issuance of 64.3 million Class A common units to Enbridge. Further, Enbridge irrevocably waived all of its rights associated with its 66.1 million Class D units and 1,000 Incentive Distribution Units, in exchange for the issuance of 1,000 Class F units. The irrevocable waiver is effective with respect to distributions declared with a record date after April 27, 2017. In connection with these strategic restructuring actions, EEP reduced its quarterly distribution from US$0.583 per unit to US$0.35 per unit.

PRIVATIZATION OF MIDCOAST ENERGY PARTNERS

On April 27, 2017, Enbridge completed its previously-announced merger through a wholly owned subsidiary, whereby it took private MEP by acquiring all of the outstanding publicly-held common units of MEP for a total consideration of approximately US$170 million.

ENBRIDGE INCOME FUND HOLDINGS INC. (ENF) SECONDARY OFFERING

On April 18, 2017, the Company and ENF completed the secondary offering of 17,347,750 ENF common shares to the public at a price of $33.15 per share, for gross proceeds to Enbridge of approximately $0.6 billion (the Secondary Offering). To effect the Secondary Offering, Enbridge exchanged 21,657,617 Fund units it owned for an equivalent amount of ENF common shares. In order to maintain its 19.9% interest in ENF, Enbridge retained 4,309,867 of the common shares it received in the exchange, and sold the balance through the Secondary Offering. Enbridge used the proceeds from the Secondary Offering to pay down short-term debt, pending reinvestment by the Company in its growing portfolio of secured projects. Upon closing of the Secondary Offering, the Company s total economic interest in ENF decreased from 86.9% to 84.6%.