ENBRIDGE INC
Form 6-K
August 03, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

Pursuant to Rule 13a-16 or 15d-16 of

the Securities Exchange Act of 1934

Dated August 3, 2017

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

200, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

Indicate by check mark whether the Registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F		Form 40-F	P

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes		No	P

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by regulation S-T Rule 101(b)(7):

Yes		No	P

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-216272, 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 333-185591) AND FORM F-10 (FILE NO. 333-213234) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Interim Report to Shareholders for the six months ended June 30, 2017

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date:	August 3, 2017	By:	/s/ Tyler W. Robinson Tyler W. Robinson Vice President & Corporate Secretary

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

June 30, 2017

GLOSSARY

Algonquin	Algonquin Gas Transmission, L.L.C.
ALJ	Administrative Law Judge
ASU	Accounting Standards Update
Average Exchange Rate	United States to Canadian dollar average exchange rate
bcf/d	Billion cubic feet per day
bpd	Barrels per day
Canadian L3R Program	Canadian portion of the Line 3 Replacement Program
CTS	Competitive Toll Settlement
EBIT	Earnings before interest and income taxes
Eddystone Rail	Eddystone Rail Company, LLC
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
Enbridge or the Company	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
EPA	United States Environmental Protection Agency
FCA	Federal Court of Appeal
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
Gulfstream	Gulfstream Natural Gas System, L.L.C.
IJT	International Joint Tariff
L3R Program	Line 3 Replacement Program
Lakehead System	Lakehead Pipeline System
LNG	Liquefied natural gas
M&N U.S.	Maritimes & Northeast Pipeline, L.L.C.
MD&A	Management s Discussion and Analysis
MEP	Midcoast Energy Partners, L.P.
mmcf/d	Million cubic feet per day
MNPUC	Minnesota Public Utilities Commission
NEB	National Energy Board
NGL	Natural gas liquids
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines
Seaway Pipeline	Seaway Crude Pipeline System
SEP	Spectra Energy Partners, LP
Spectra Energy	Spectra Energy Corp
Texas Eastern	Texas Eastern Transmission, L.P.
the Fund	Enbridge Income Fund
the Fund Group	Enbridge Income Fund, Enbridge Commercial Trust, Enbridge Income Partners LP and the subsidiaries and investees of Enbridge Income Partners LP
the Merger Transaction	The stock-for-stock merger transaction between Enbridge and Spectra Energy

the Tupper Plants	Tupper Main and Tupper West gas plants
Union Gas	Union Gas Limited
U.S. GAAP	Generally accepted accounting principles in the United States of America
U.S. L3R Program	United States portion of the Line 3 Replacement Program
Westcoast	Westcoast Energy Inc.

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2017

This Management s Discussion and Analysis (MD&A) dated August 3, 2017 should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and six months ended June 30, 2017, prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). It should also be read in conjunction with the Company s audited consolidated financial statements and MD&A for the year ended December 31, 2016 filed on February 17, 2017. For information relating to assets and operations acquired through the combination with Spectra Energy Corp (Spectra Energy), additional information is also available in Spectra Energy s audited consolidated financial statements and MD&A for the year ended December 31, 2016 filed on SEDAR on February 24, 2017. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

MERGER WITH SPECTRA ENERGY

On February 27, 2017, Enbridge announced the closing of the previously announced combination of Enbridge and Spectra Energy through a stock-for-stock merger transaction (the Merger Transaction).

Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge for each share of Spectra Energy common stock they held. Upon closing of the Merger Transaction, Enbridge shareholders owned approximately 57% of the combined company and Spectra Energy shareholders owned approximately 43%.

Spectra Energy, now wholly-owned by Enbridge, is one of North America s leading natural gas delivery companies owning and operating a large, diversified and complementary portfolio of gas transmission, midstream gathering and processing and distribution assets. It also owns and operates a crude oil pipeline system that connects Canadian and United States producers to refineries in the United States Rocky Mountain and Midwest regions. The combination with Spectra Energy has created the largest energy infrastructure company in North America with an extensive portfolio of energy assets that are well positioned to serve key supply basins and end use markets and multiple business platforms through which to drive future growth. At the time of closing of the Merger Transaction, the Company s capital program included $27 billion of commercially secured growth projects, which are expected to come into service through 2019, and an additional portfolio of projects in earlier stages of development expected to come into service by 2024. These growth projects, together with Enbridge s existing businesses, are expected to generate dividend growth of 10% to 12% on average through 2024.

A more detailed description of each of the businesses and underlying assets acquired through the Merger Transaction is provided under *Financial Results* within this MD&A. The results of operations from assets acquired through the Merger Transaction are included in Enbridge s financial statements and in this MD&A on a prospective basis from the closing date of the Merger Transaction.

Post-combination, the Company s activities continue to be carried out through five business segments: Liquids Pipelines; Gas Pipelines and Processing; Gas Distribution; Green Power and Transmission; and Energy Services. Effective February 27, 2017, as a result of the Merger Transaction, and in addition to Enbridge assets previously held:

- Liquids Pipelines also includes results from the operation of the Express-Platte System.

- Gas Pipelines and Processing also includes Spectra Energy s United States Storage and Transmission Assets, Canadian British Columbia Pipeline & Field Services, Canadian Midstream and Maritimes & Northeast U.S. and Canada businesses, as well as the results of the Company s 50% interest in DCP Midstream, LLC (DCP Midstream).

- Gas Distribution also includes results from the operation of Union Gas Limited (Union Gas).

A number of the assets acquired through the Merger Transaction and included in the business segments discussed above are owned through the Company s investment in Spectra Energy Partners, LP (SEP). As a result of the combination, Enbridge now holds a 75% equity interest in SEP, a natural gas and crude oil infrastructure master limited partnership, which owns 100% of Texas Eastern Transmission, L.P. (Texas Eastern), 91% of Algonquin Gas Transmission, L.L.C. (Algonquin), 100% of East Tennessee Natural Gas, L.L.C. (East Tennessee), 100% of Express-Platte, 100% of Saltville Gas Storage Company L.L.C. (Saltville), 100% of Ozark Gas Gathering, L.L.C. and Ozark Gas Transmission, L.L.C., 100% of Big Sandy Pipeline, L.L.C., 100% of Market Hub Partners Holding, 100% of Bobcat Gas Storage, 78% of Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.), 50% of Southeast Supply Header, L.L.C., 50% of Steckman Ridge, L.P. and 50% of Gulfstream Natural Gas System, L.L.C. (Gulfstream).

UNITED STATES SPONSORED VEHICLE STRATEGY

On April 28, 2017, Enbridge announced the completion of the strategic review of Enbridge Energy Partners, L.P. (EEP). The following actions, together with the measures announced in January 2017 and disclosed in the Company s 2016 annual MD&A, were taken to enhance EEP s value proposition to its unitholders and to Enbridge:

Acquisition of Midcoast Assets and Privatization of Midcoast Energy Partners, L.P.

On April 27, 2017, Enbridge completed its previously-announced merger through a wholly-owned subsidiary, through which it privatized Midcoast Energy Partners, L.P. (MEP) by acquiring all of the outstanding publicly-held common units of MEP for total consideration of approximately US$170 million.

On June 28, 2017, Enbridge, through a wholly-owned subsidiary, acquired all of EEP s interest in the Midcoast gas gathering and processing business for cash consideration of US$1.3 billion plus existing indebtedness of MEP of US$953 million.

As a result of the above transactions, 100% of the Midcoast gas gathering and processing business is now owned by Enbridge.

Finalization of Bakken Pipeline System Joint Funding Agreement

On February 15, 2017, EEP acquired an effective 27.6% interest in the Dakota Access and Energy Transfer Crude Oil Pipelines (collectively, the Bakken Pipeline System). On April 27, 2017, Enbridge entered into a joint funding arrangement with EEP whereby Enbridge owns 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System. Under this arrangement, EEP has retained a five-year option to acquire an additional 20% interest. On finalization of this joint funding arrangement, EEP repaid the outstanding balance on its US$1.5 billion credit agreement with Enbridge, which it had drawn upon to fund the initial purchase.

EEP Strategic Restructuring Actions

On April 27, 2017, 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 (IDUs), in exchange for the issuance of 1,000

Class F units. The Class F units are entitled to (i) 13% of all distributions in excess of US$0.295 per EEP unit, but equal to or less than US$0.35 per EEP unit, and (ii) 23% of all distributions in excess of US$0.35 per EEP unit. 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.

The irrevocable waiver of the Class D units and IDUs, the redemption of the Series 1 Preferred Units and the reduction in the quarterly distributions will result in a lower contribution of earnings from EEP. This lower contribution will be partially offset by an increased contribution of earnings as a result of Enbridge s increased ownership in the Class A common units post restructuring.

ASSET MONETIZATION

In conjunction with the announcement of the Merger Transaction in September 2016, the Company announced its intention to divest $2 billion of assets over the ensuing 12 months in order to further strengthen its post-combination balance sheet and enhance the financial flexibility of the combined entity. With the completion of the secondary offering noted below, the Ozark pipeline system sale, the Olympic refined products pipeline sale and other divestitures completed in 2016, the Company has exceeded the $2 billion monetization target.

On April 18, 2017, the Company and Enbridge Income Fund Holdings Inc. (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 Enbridge Income Fund (Fund) units it owned for an equivalent amount of ENF common shares. In order to maintain its 19.9% ownership interest in ENF, Enbridge retained 4,309,867 of the common shares it received in the exchange, and sold the balance under 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%.

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**1,272**	643	**2,396**	2,255
Gas Pipelines and Processing	**682**	19	**1,021**	80
Gas Distribution	**153**	83	**428**	322
Green Power and Transmission	**51**	41	**101**	90
Energy Services	**(18)**	(7)	**138**	(13)
Eliminations and Other	**(41)**	(48)	**(356)**	173
Earnings before interest and income taxes	**2,099**	731	**3,728**	2,907
Interest expense	**(565)**	(369)	**(1,051)**	(781)
Income tax expense	**(293)**	(10)	**(491)**	(427)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(241)**	20	**(465)**	(41)
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Earnings attributable to common shareholders	**919**	301	**1,557**	1,514
Earnings per common share	**0.56**	0.33	**1.11**	1.69
Diluted earnings per common share	**0.56**	0.33	**1.10**	1.67

EARNINGS BEFORE INTEREST AND INCOME TAXES

For the three and six months ended June 30, 2017, earnings before interest and income taxes (EBIT) were $2,099 million and $3,728 million, respectively, compared with $731 million and $2,907 million for the three and six months ended June 30, 2016. Earnings for the three and six months ended June 30, 2017 were positively impacted by contributions from new assets following the completion of the Merger Transaction on February 27, 2017.

The positive impact to EBIT resulting from the Merger Transaction s new assets was partially offset by lower results in Energy Services and the Liquids Pipelines segment as discussed below.

The comparability of the Company s earnings period-over-period is also impacted by a number of unusual, non-recurring or non-operating factors that are enumerated in the Non-GAAP Reconciliation tables, the most significant of which are changes in unrealized derivative fair value gains and losses. For the three months ended June 30, 2017, the Company s EBIT reflected $461 million of unrealized derivative fair value gains, compared with losses of $98 million in the corresponding 2016 period. For the six months ended June 30, 2017, the Company s EBIT reflected $877 million of unrealized derivative fair value gains, compared with gains of $834 million in the corresponding 2016 period. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks which creates volatility in short-term earnings. Over the long term, Enbridge believes its hedging program supports the reliable cash flows and dividend growth upon which the Company s investor value proposition is based.

In addition, the comparability of period-over-period EBIT was impacted by the recognition of an impairment of $176 million ($103 million after-tax attributable to Enbridge) in the second quarter of 2016 related to Enbridge s 75% joint venture interest in Eddystone Rail Company, LLC (Eddystone Rail), a rail-to-barge transloading facility located in Greater Philadelphia, Pennsylvania.

EBIT for the six months ended June 30, 2017 also reflected charges of $178 million ($130 million after-tax) with respect to costs incurred in conjunction with the Merger Transaction, as well as $208 million ($146 million after-tax) of employee severance costs in relation to the Company s enterprise-wide reduction of workforce in March 2017 and restructuring costs in connection with the completion of the Merger Transaction.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders for the three months ended June 30, 2017 were $919 million, or $0.56 per common share, compared with $301 million, or $0.33 per common share, for the three months ended June 30, 2016. Earnings attributable to common shareholders for the six months ended June 30, 2017 were $1,557 million, or $1.11 per common share, compared with $1,514 million, or $1.69 per common share, for the six months ended June 30, 2016.

In addition to the factors discussed in *Earnings Before Interest and Income Taxes* above, interest expense for the three and six months ended June 30, 2017 was higher, compared with the corresponding 2016 periods, as a result of debt assumed in the Merger Transaction. Preference share dividends were also higher reflecting additional preference shares issued in the fourth quarter of 2016 to partially fund the Company s growth capital program.

Income tax expense increased for the three and six months ended June 30, 2017, compared with the corresponding 2016 periods, largely due to the increase in earnings.

Earnings attributable to noncontrolling interests and redeemable noncontrolling interests increased in the second quarter and the first half of 2017, compared with the corresponding 2016 periods. The increase was driven by additional noncontrolling interests associated with the assets acquired in the Merger Transaction and lower earnings attributable to noncontrolling interests in EEP during 2016.

Lower earnings per common share for the six months ended June 30, 2017, compared with the corresponding 2016 period, reflected the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction, the issuance of approximately 75 million common shares in 2016 through a 56 million follow-on common share offering in the first quarter of 2016, and ongoing issuances under the Company s Dividend Reinvestment Program.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , believe , likely and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines business; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for the Company s commercially secured growth program; expected future growth and expansion opportunities; expectations about the Company s joint venture partners ability to complete and finance projects under construction; expected closing of acquisitions and dispositions; estimated future dividends; recovery of the costs of the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program); expected expansion of the T-South System; expected capacity of the Hohe See Expansion Offshore Wind Project; expected costs in connection with Line 6A and Line 6B crude oil releases; expected effect of Aux Sable Consent Decree; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the Merger Transaction including the combined Company s scale, financial flexibility, growth program, future business prospects and performance; impact of the Canadian L3R Program on existing integrity programs; dividend payout policy; dividend growth and dividend payout expectation; and expectations on impact of hedging program.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labour and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company s projects; anticipated in-service dates; weather; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of the dividend policy on the Company s future cash flows; credit ratings; capital project funding; expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to the impact of the Merger Transaction on the Company, expected EBIT, adjusted EBIT, earnings/(loss), adjusted earnings/(loss) and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labour and construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.

Enbridge s forward-looking statements are subject to risks and uncertainties pertaining to the impact of the Merger Transaction, operating performance, regulatory parameters, dividend policy, project approval and support, renewals of rights of way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted EBIT, adjusted earnings and adjusted earnings per common share. Adjusted EBIT represents EBIT adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors included in adjusted EBIT, as well as adjustments for unusual, non-recurring or non-operating factors in respect of interest expense, income taxes, noncontrolling interests and redeemable noncontrolling interests on a consolidated basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments.

Management believes the presentation of adjusted EBIT, adjusted earnings and adjusted earnings per share gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Management uses adjusted EBIT and adjusted earnings to set targets and to assess the performance of the Company. Adjusted EBIT, adjusted EBIT for each segment, adjusted earnings and adjusted earnings per common share are not measures that have standardized meaning prescribed by U.S. GAAP and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers.

The tables below provide a reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATION EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Earnings before interest and income taxes	**2,099**	731	**3,728**	2,907
Adjusting items[1]:				
Change in unrealized derivative fair value (gain)/loss[2]	**(461)**	98	**(877)**	(834)
Assets and investment impairment loss	**-**	187	**-**	187
Unrealized intercompany foreign exchange (gain)/loss	**7**	(5)	**14**	55
Hydrostatic testing	**-**	-	**-**	(12)
Make-up rights adjustments[3]	**-**	48	**-**	115
Northeastern Alberta wildfires pipelines and facilities restart costs	**-**	21	**-**	21
Leak remediation costs, net of leak insurance recoveries	**4**	1	**8**	16
Warmer/(colder) than normal weather[4]	**-**	(9)	**-**	8
Project development and transaction costs	**50**	3	**203**	3
Employee severance and restructuring costs	**79**	8	**208**	8
Other	**(65)**	6	**(56)**	(11)
Adjusted earnings before interest and income taxes	**1,713**	1,089	**3,228**	2,463
Interest expense	**(565)**	(369)	**(1,051)**	(781)
Income taxes	**(293)**	(10)	**(491)**	(427)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(241)**	20	**(465)**	(41)
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Adjusting items in respect of:				
Interest expense	**(23)**	6	**(2)**	24
Income taxes	**99**	(121)	**153**	120
Noncontrolling interests and redeemable noncontrolling interests	**53**	(88)	**129**	(95)
Adjusted earnings	**662**	456	**1,337**	1,119

1 *The above table summarizes adjusting items by nature. For a detailed listing of adjusting items by segment, refer to individual segment discussions.*
2 *Changes in unrealized derivative fair value gains and losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.*
3 *Effective January 1, 2017, the Company no longer makes such an adjustment to its EBIT. For further details refer to Financial Results - Liquids Pipelines.*
4 *Effective January 1, 2017, the Company no longer makes such an adjustment to its EBIT. For further details refer to Financial Results - Gas Distribution.*

NON-GAAP RECONCILIATION ADJUSTED EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**938**	922	**1,908**	2,006
Gas Pipelines and Processing	**667**	90	**1,003**	177
Gas Distribution	**153**	73	**422**	313
Green Power and Transmission	**51**	40	**101**	88
Energy Services	**(3)**	47	**(8)**	48
Eliminations and Other	**(93)**	(83)	**(198)**	(169)
Adjusted earnings before interest and income taxes	**1,713**	1,089	**3,228**	2,463
Interest expense[1]	**(588)**	(363)	**(1,053)**	(757)
Income taxes[1]	**(194)**	(131)	**(338)**	(307)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(188)**	(68)	**(336)**	(136)
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Adjusted earnings	**662**	456	**1,337**	1,119
Adjusted earnings per common share	**0.41**	0.50	**0.95**	1.25

1 These balances are presented net of adjusting items.

Adjusted EBIT

For the three and six months ended June 30, 2017, adjusted EBIT was $1,713 million and $3,228 million, respectively, an increase of $624 million and $765 million over the corresponding three and six-month periods in 2016. The largest driver of adjusted EBIT growth over the prior year periods was the contributions of new assets acquired in the Merger Transaction which closed on February 27, 2017. Also contributing to the period-over-period growth in adjusted EBIT were increased contributions from the Green Power and Transmission segment. These positive contributions were partially offset by warmer weather in the franchise areas served by the Company s gas distribution utilities and lower results in the Energy Services and Liquids Pipelines segments.

Growth in adjusted EBIT was most pronounced in the Gas Pipelines and Processing segment, where a majority of the new assets acquired through the Merger Transaction are reported. Growth for this segment also reflected contributions from the Tupper Main and Tupper West gas plants (the Tupper Plants) acquired in April 2016.

Excluding contributions from Express-Platte as part of the Merger Transaction, Liquids Pipelines adjusted EBIT decreased in the three and six months ended June 30, 2017, compared with the corresponding 2016 periods. The second quarter of 2017 was impacted by several transitory items including a significant unexpected outage and accelerated maintenance at a customer s upstream facility, additional related and unrelated production disruptions, and a hydrostatic testing program on Line 5 during the month of June 2017. The combined impact on the mainline system of these factors was approximately $50 million in the second quarter of 2017. Up until the month of June, the mainline system had been delivering near record volumes and operating under apportionment in heavy crude oil service. Apportionment on the mainline system also impacted the adjusted EBIT contribution of certain downstream pipelines during the first and second quarters of 2017. Liquids Pipelines reported performance was further impacted by a change in practice whereby the Company no longer includes cash received under certain take-or-pay contracts with make-up rights in its determination of adjusted EBIT. In addition, the divestiture of certain assets and lower surcharge revenues decreased adjusted EBIT. Adjusted EBIT generated by Liquids Pipelines is expected to grow over the second half of 2017 as throughput on the mainline system is expected to return to record levels achieved earlier in the year and capacity optimization projects, undertaken in the first half of the year to alleviate apportionment on the mainline system, are operationalized.

Within the Gas Distribution segment, Enbridge Gas Distribution Inc. (EGD) generated lower adjusted EBIT for the six months ended June 30, 2017, compared with the corresponding 2016 period, primarily due to lower distribution revenues attributable to warmer than normal weather in the first half of 2017. Effective January 1, 2017, EGD ceased to exclude the effect of warmer/colder weather from its adjusted EBIT. In the first half of 2017 warmer than normal weather impacted EGD s adjusted EBIT by approximately $23 million. The period-over-period decrease in EGD s adjusted EBIT was more than offset by contributions from Union Gas since the completion of the Merger Transaction.

Energy Services adjusted EBIT for the three and six months ended June 30, 2017 reflected compressed location and quality differentials in certain markets, lower refinery demand for certain products and fewer opportunities to achieve profitable margins on facilities where the Company holds capacity obligations. Adjusted EBIT from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

The increase in adjusted loss before interest and income taxes reported within Eliminations and Other reflects higher unallocated corporate costs which primarily resulted from the Merger Transaction, partially offset by synergies achieved thus far on integration of corporate functions.

Adjusted Earnings

Adjusted earnings were $662 million, or $0.41 per common share, for the three months ended June 30, 2017, compared with $456 million, or $0.50 per common share, for the three months ended June 30, 2016. Adjusted earnings were $1,337 million, or $0.95 per common share, for the six months ended June 30, 2017, compared with $1,119 million, or $1.25 per common share, for the six months ended June 30, 2016.

In addition to the factors discussed in *Adjusted EBIT* above, the comparability of adjusted earnings is consistent with the discussion in *Earnings Attributable to Common Shareholders* above.

GROWTH PROJECTS   COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of the Company s commercially secured projects, organized by business segment. Expenditures to date reflect total cumulative expenditures incurred from inception of the project to June 30, 2017.

(Canadian dollars, unless stated otherwise)		**Estimated Capital Cost1**	**Expenditures to Date**	**Expected In-Service Date**	**Status**
LIQUIDS PIPELINES					
1.	Norlite Pipeline System (the Fund Group)	$1.3 billion	$1.1 billion	2017	Complete
2.	Bakken Pipeline System (EEP)	US$1.5 billion	US$1.5 billion	2017	Complete
3.	Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$2.3 billion	2017 (in phases)	Substantially complete
4.	Lakehead System Mainline Expansion - Line 61 (EEP)	US$0.4 billion	US$0.4 billion	2019	Substantially complete
5.	Canadian Line 3 Replacement2 Program (the Fund Group)	$5.3 billion	$1.7 billion	2019	Pre-construction
6.	U.S. Line 3 Replacement Program2 (EEP)	US$2.9 billion	US$0.5 billion	2019	Under construction
7.	Other - Canada	$0.3 billion	$0.1 billion	2017-2018	Various stages
GAS PIPELINES AND PROCESSING					
8.	Sabal Trail (SEP)3	US$1.6 billion	US$1.4 billion	2017	Complete
9.	Access South, Adair Southwest and Lebanon Extension (SEP)3	US$0.5 billion	US$0.2 billion	2017	Under construction
10.	Atlantic Bridge (SEP)3	US$0.5 billion	US$0.2 billion	2017-2018	Under construction
11.	NEXUS (SEP)3	US$1.1 billion	US$0.5 billion	2018	Pre-construction
12.	High Pine3	$0.4 billion	$0.2 billion	2017	Under construction
13.	Reliability and Maintainability Project3	$0.5 billion	$0.3 billion	2017-2018	Under construction
14.	Valley Crossing Pipeline3	US$1.5 billion	US$0.5 billion	2018	Under construction
15.	Spruce Ridge Program3	$0.5 billion	No significant expenditures to date	2019	Pre-construction
16.	British Columbia Pipeline3 T-South System	$1.0 billion	No significant expenditures to date	2020	Pre-construction
17.	Other - United States3	US$1.6 billion	US$0.9 billion	2017-2019	Various stages
18.	Other - Canada3	$0.4 billion	$0.2 billion	2017-2018	Various stages

		Estimated Capital Cost1	Expenditures to Date	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
GAS DISTRIBUTION					
19.	2017 Dawn-Parkway Expansion3	$0.6 billion	$0.5 billion	2017	Under construction
20.	Other - Canada3	$0.3 billion	$0.1 billion	2017	Under construction
GREEN POWER AND TRANSMISSION					
21.	Chapman Ranch Wind Project	US$0.4 billion	US$0.3 billion	2017	Under construction
22.	Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.5 billion (£0.3 billion)	2018	Under construction
23.	Hohe See Offshore Wind Project4	$1.7 billion (1.07 billion)	$0.5 billion (0.3 billion)	2019	Pre-construction
24.	Hohe See Expansion Project	$0.4 billion (0.27 billion)	No significant expenditures to date	2019	Pre-construction

1 *These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge s share of joint venture projects.*
2 *Based on the updated execution plan, the updated project capital costs are $5.3 billion in Canada and US$2.9 billion in the United States.*
3 *Includes projects acquired as part of the Merger Transaction. For additional information, refer to Merger with Spectra Energy.*
4 *In February 2017, Enbridge acquired an effective 50% interest in the Hohe See Offshore Wind Project.*

The description of each of the Enbridge projects, including those being undertaken by EEP and the Fund Group, which is comprised of the Fund, Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and the subsidiaries and investees of EIPLP, is provided in the Company s 2016 annual MD&A. Projects where significant developments have occurred since February 17, 2017, the date of the filing of the Company s MD&A for the year ended December 31, 2016, including the commercially secured growth projects acquired upon close of the Merger Transaction, are discussed below.

LIQUIDS PIPELINES

Norlite Pipeline System (the Fund Group)

Norlite Pipeline System, a new industry diluent pipeline originating from the Company s Stonefell Terminal, was placed into commercial service on May 1, 2017. To meet the needs of multiple producers in the Athabasca oil sands region, the 24-inch diameter pipeline provides an initial capacity of approximately 218,000 Barrels per day (bpd) of diluent, with the potential to be further expanded to approximately 465,000 bpd of capacity with the addition of pump stations. Keyera Corp. has elected to participate in the Norlite Pipeline System as a 30% non-operating owner.

Bakken Pipeline System (EEP)

On February 15, 2017, EEP acquired an effective 27.6% interest in the Bakken Pipeline System for a purchase price of $2.0 billion (US$1.5 billion). The Bakken Pipeline System was placed into service on June 1, 2017. It connects the Bakken formation in North Dakota to markets in the eastern Petroleum Administration for Defense Districts and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost.

On April 27, 2017, Enbridge entered into a joint funding arrangement with EEP whereby Enbridge owns 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System.

Lakehead System Mainline Expansion (EEP)

The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead Pipeline System (Lakehead System) mainline between its origin at the United States/Canada border, near Neche, North Dakota, and Flanagan, Illinois. These projects include the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61) and the construction of the Spearhead North Twin pipeline (Line 78). The expansion of Line 67 and construction of Line 78 were completed in 2015.

The Line 67 pipeline capacity expansion remains subject to the receipt of an amendment to the current Presidential Permit to allow for operation of the Line 67 pipeline at the United States/Canada border at its currently planned operating capacity of 800,000 bpd. On February 10, 2017, the United States Department of State (DOS), the agency that is responsible for issuing permits for cross-border pipelines pursuant to a delegation of authority by the President under an Executive Order, issued a draft Supplemental Environmental Impact Statement (SEIS), which determined that there were no significant adverse environmental impacts from the planned capacity increase. The public comment period on the draft SEIS closed on March 27, 2017. The DOS is reviewing all received comments and preparing a final SEIS. As required by the Executive Order, the DOS initiated a 90-day inter-agency consultation period to solicit comments from certain other federal agencies on whether the Line 67 expansion will serve the national interest. The inter-agency consultation period commenced on March 28, 2017. Following the issuance of the final SEIS and completion of the inter-agency consultation process, the Administration will make a decision and issue a Presidential Permit if it finds that doing so is in the national interest. The Administration s decision is expected later in the year.

The remaining scope of the Lakehead System Mainline Expansion included the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois. The expansion to increase the pipeline capacity to 1,200,000 bpd at an expected cost of approximately US$0.4 billion was substantially completed in June of 2017. In conjunction with shippers, a decision was made to delay the in-service date of this phase of the Southern Access expansion to 2019 to align more closely with the anticipated in-service date for the United States portion of the Line 3 Replacement Program (U.S. L3R Program).

EEP will operate this project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP under a joint funding agreement. Under that agreement, EEP has the option to increase its economic interest held by up to an additional 15% at cost.

Line 3 Replacement Program

The Line 3 Replacement Program (L3R Program) will support the safety and operational reliability of the mainline system, enhance system flexibility, allow the Company and EEP to optimize throughput on the mainline system and restore approximately 370,000 bpd of capacity from western Canada into Superior, Wisconsin.

Canadian Line 3 Replacement Program (the Fund Group)

The Canadian L3R Program will complement existing integrity programs by replacing approximately 1,084 kilometres (673 miles) of the remaining line segments of the existing Line 3 pipeline between Hardisty, Alberta and Gretna, Manitoba.

In April 2016, the National Energy Board (NEB) found that the Canadian L3R Program is in the Canadian public interest and issued final conditions and a recommendation to the Federal Cabinet to approve the issuance of the Certificate of Public Convenience and Necessity (the Certificate) for the construction and operation of the pipeline and related facilities. Approval was received from the Government of Canada on November 29, 2016, with no material changes to permit conditions and on December 1, 2016, the NEB issued the Certificate. Once the Certificate was issued, Natural Resources Canada (NRCan) released the final assessment of the upstream greenhouse gas (GHG) emissions, as well as reports summarizing the additional Crown Consultation with Indigenous groups and the public online survey conducted by NRCan.

In December 2016, the Manitoba Metis Federation (MMF) and the Association of Manitoba Chiefs (AMC) applied to the Federal Court of Appeal (FCA) for leave, which was subsequently granted, to judicially review the Government of Canada s decision to approve the Canadian L3R Program. On July 4, 2017, the MMF discontinued its judicial review application. It is expected that the FCA s hearing of the AMC judicial review application will take place during 2018, although a hearing date has not yet been set. The potential outcome of this matter cannot be predicted at this time.

On July 7, 2017, the NEB approved the Plan, Profile and Book of Reference for the Canadian L3R Program, meaning that the detailed route for the Canadian L3R Program has been approved. All required pre-construction filings have been submitted to the NEB. Enbridge is awaiting the approval of the two remaining conditions by the NEB before construction can proceed.

Based on the updated execution plan, the revised cost of the project is $5.3 billion in Canada. This modest increase is roughly 8% above prior estimates and reflects the ongoing delays in the regulatory process, as well as some additional scope, route modifications and other changes as a result of the extensive consultation efforts and obligation to meet permit conditions. The impact of these additional costs are fully offset by lower estimated operating costs and a stronger United States dollar relative to the original project assumptions.

United States Line 3 Replacement Program (EEP)

The U.S. L3R Program will complement existing integrity programs by replacing approximately 576 kilometres (358 miles) of the remaining line segments of the existing Line 3 pipeline between Neche, North Dakota and Superior, Wisconsin. EEP has the authorization to replace Line 3 in North Dakota and Wisconsin.

EEP is in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need and an approval of the pipeline s route (Route Permit) from the Minnesota Public Utilities Commission (MNPUC). The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. On February 1, 2016, the MNPUC issued a written order requiring the Minnesota Department of Commerce (DOC) to prepare an Environmental Impact Statement (EIS) before Certificate of Need and Route Permit processes commence. The DOC s draft EIS was issued on May 15, 2017 and public comments regarding the draft EIS were accepted by the DOC until July 10, 2017. The DOC has stated that it anticipates issuing the final EIS in August 2017. Construction of the Wisconsin portion of U.S. L3R Program commenced in late June 2017.

Based on the updated execution plan, the revised cost of the project is US$2.9 billion in the United States. This modest increase is roughly 12% above prior estimates and reflects the ongoing delays in the regulatory process, as well as some additional scope, route modifications and other changes as a result of the extensive consultation efforts and obligation to meet permit conditions. EEP will recover the costs plus a return on capital based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost-of-service methodology.

On January 26, 2017, Enbridge and EEP entered into an agreement for the joint funding of the U.S. L3R Program, whereby Enbridge and EEP will fund 99% and 1%, respectively, of the project cost. Enbridge has reimbursed EEP approximately US$450 million for expenditures incurred to date on the project and it will fund 99% of the capital costs through construction. EEP has the option to increase its economic interest by up to 40% at Enbridge s cost until four years after the project is placed into service.

GAS PIPELINES AND PROCESSING

Sabal Trail (SEP)

The Sabal Trail project, a joint venture with NextEra Energy and Duke Energy, was placed into service in early July 2017. The project will provide firm natural gas transportation to Florida Power & Light Company for its power generation needs and to Duke Energy Florida for its proposed natural gas plant in Florida. Facilities include a new 748 kilometre (465 mile) pipeline, laterals and various compressor stations. This new pipeline infrastructure is located in Alabama, Georgia and Florida, and will add approximately 1,100 million cubic feet per day (mmcf/d) of new capacity to access onshore shale gas supplies once approved future expansions are completed.

Access South, Adair Southwest and Lebanon Extension (SEP)

SEP s Access South, Adair Southwest and Lebanon Extension projects will provide shippers with the opportunity to deliver new natural gas supplies from the Appalachian region of the United States to markets in the Midwest and Southeast regions of the United States where demand for natural gas is high. The facilities for these projects include pipeline looping, as well as modifications and expansions of existing compressor stations on SEP s Texas Eastern pipeline system. The combined projects are designed to deliver 622 mmcf/d of gas to customers in Ohio, Kentucky and Mississippi. These projects are expected to be placed into service in the second half of 2017.

Atlantic Bridge (SEP)

The Atlantic Bridge project is an expansion designed to provide additional capacity of 133 mmcf/d to SEP s Algonquin Gas Transmission and Maritimes & Northeast pipeline systems into New England and to specific end use markets in the Canadian Maritime provinces. The expansion primarily consists of the replacement of 10 kilometres (6 miles) of 26-inch pipeline with 42-inch pipeline, compression additions in Connecticut and a new compressor station in Massachusetts. The Connecticut portion of the project is expected to be placed into service in the fourth quarter of 2017. The Massachusetts portion of the project is expected to be placed into service in late 2018.

NEXUS (SEP)

Under a 50% joint venture with DTE Energy Company, SEP has begun pre-construction work on the NEXUS project, which is a new pipeline system designed to transport up to 1.5 billion cubic feet per day (bcf/d) from SEP s Texas Eastern pipeline system in Ohio to the Union Gas Dawn hub in Ontario. The facilities will consist of approximately 410 kilometres (255 miles) of 36-inch pipeline across northern Ohio to the Detroit, Michigan area, addition of four new compressor stations totalling 130,000 horsepower and six meter stations. Approval of the NEXUS project remains pending before the Federal Energy Regulatory Commission (FERC) due to a lack of quorum. While the NEXUS certificate application remains pending, the record supporting the Final EIS and Applications are complete and ready for prompt FERC approval once a quorum is restored. Once the expected approval is received, a revised 2018 in-service date will be identified.

High Pine

Westcoast s High Pine project on the British Columbia Pipeline includes a 240 mmcf/d expansion of the T-North pipeline system consisting of two 42-inch pipeline loops totalling approximately 37 kilometres (23 miles) in length in the Fort St. John region of British Columbia. The expansion consists of an additional compressor unit with associated infrastructure at the Sunset Creek compressor site in northeastern British Columbia. The project is expected to be placed into service by the end of 2017.

Reliability and Maintainability Project

Westcoast s Reliability and Maintainability (RAM) project was designed to enhance the performance of the southern segment of the British Columbia Pipeline system to accommodate the increased base load on the system, which is driven by a combination of increased gas production in the northeastern region of British Columbia and demand driven by end users, such as incremental industrial projects, electric power generation and small-scale liquefied natural gas (LNG). The RAM project involves upgrading the southern segment of the British Columbia Pipeline system with three compressor station replacements. It will prepare the British Columbia Pipeline system to operate at a higher load factor as higher utilization rates are expected from new incremental year-round loads. The first two compressor stations are expected to be placed into service in the fourth quarter of 2017, with the final station expected to be placed into service in the first half of 2018.

Valley Crossing Pipeline

The Valley Crossing Pipeline project will provide new market opportunities for Texas gas producers and help Mexico meet its growing electric generation needs as generators shift away from fuel oil and imported LNG. The project will include a new 269 kilometre (167 mile) mainline pipeline that will consist of approximately 221 kilometres (138 miles) of 48-inch pipe and 48 kilometres (30 miles) of 42-inch pipe. The pipeline is designed to carry 2.6 bcf/d of gas from the Agua Dulce hub in Texas to an offshore tie-in with the Sur de Texas-Tuxpan project, which is being constructed by a third party. The Valley Crossing Pipeline is expected to be placed into service in the second half of 2018.

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Spruce Ridge Program

Under the Spruce Ridge Program, Westcoast is pursuing an expansion of the British Columbia Pipeline in northern British Columbia. The expansion service agreements were executed in late 2016 and the final scoping of the project is underway, with a targeted in-service date in 2019.

British Columbia Pipeline T-South System

In the second quarter of 2017, Enbridge completed a successful binding open season on its British Columbia Pipeline T-South system for delivery of an incremental 190 mmcf/d of natural gas into the Huntington/Sumas market at the United States/Canada border. All customer contracts associated with the open season have been executed. The T-South system is currently fully contracted and an expansion is necessary to meet increasing customer demand as a result of rapidly growing production in the Montney region. The project will include looping of the T-South system and upgrades at compressor stations along the pipeline system at a cost of approximately $1 billion and is expected to be in-service by late 2020.

GAS DISTRIBUTION

2017 Dawn-Parkway Expansion

The Union Gas 2017 Dawn-Parkway expansion project in Ontario involves a 419 mmcf/d expansion of the Dawn to Parkway transmission system consisting of the addition of a new 44,500 horsepower compressor at each of the Dawn, Lobo and Bright compressor stations in Ontario. The Dawn-Parkway expansion project is expected to be placed into service in the fourth quarter of 2017.

GREEN POWER AND TRANSMISSION

Hohe See Expansion Project

In June 2017, the Company announced it had moved forward on its option to partner with German utility EnBW on an expansion of the previously announced Hohe See Offshore Wind Project (Hohe See Project). The Hohe See expansion project, to be located in the vicinity of the 497 megawatt Hohe See Project, will have a capacity of 112 megawatts. Similar to the Hohe See Project, the Hohe See expansion project will be constructed under fixed-price engineering, procurement, construction and installation contracts which have been secured with key suppliers. The Hohe See expansion project is backed by a government legislated 20-year revenue support mechanism and is expected to be placed into service alongside the Hohe See Project in 2019.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met the Company s criteria to be classified as commercially secured. The Company also has a large portfolio of additional projects under development that have not yet progressed to the point of public announcement.

GAS PIPELINES AND PROCESSING

Gulf Coast Express Pipeline Project

In April 2017, DCP Midstream announced the signing of a letter of intent with Kinder Morgan Texas Pipeline LLC to participate in the development of the proposed Gulf Coast Express Pipeline Project. The project will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. The project is designed to transport up to 1.7 bcf/d of natural gas through approximately 692 kilometres (430 miles) of 42-inch pipeline from the Waha, Texas area to Agua Dulce, Texas. The project is expected to be placed into service during the second half of 2019, subject to obtaining sufficient shipper commitments.

GREEN POWER AND TRANSMISSION

Éolien Maritime France SAS

Enbridge has a 50% interest in Éolien Maritime France SAS (EMF), a French offshore wind development company. EMF is co-owned by Enbridge and EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF, through subsidiary companies, which holds licenses for three large-scale offshore wind farms off the coast of France. Combined, the three projects will have a capacity of 1,428 megawatts of power. The development of these projects is subject to a final investment decision and regulatory approvals, the timing of which is not yet certain. Enbridge s portion of the costs incurred to date is approximately $226 million (148 million).

FINANCIAL RESULTS

For assets owned by Enbridge as at December 31, 2016, a description of the asset and associated risks can be found under the relevant segment discussion in the Company s MD&A for the year ended December 31, 2016. For assets acquired through the Merger Transaction, the description of the asset and any additional risks specifically associated with these assets have been included with the discussion of the operating results of individual assets that follows. The performance summaries below reflect the financial results of the assets acquired in the Merger Transaction from the closing date of the merger.

LIQUIDS PIPELINES

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Canadian Mainline	**234**	177	**471**	486
Lakehead System	**300**	359	**689**	712
Regional Oil Sands System	**91**	88	**184**	181
Mid-Continent and Gulf Coast	**128**	160	**246**	341
Southern Lights Pipeline	**43**	39	**85**	80
Express-Platte System[1]	**56**	-	**83**	-
Bakken System	**50**	54	**82**	108
Feeder Pipelines and Other	**36**	45	**68**	98
Adjusted earnings before interest and income taxes	**938**	922	**1,908**	2,006
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**266**	(12)	**421**	556
Canadian Mainline - leak remediation costs	**(5)**	-	**(12)**	-
Lakehead system - changes in unrealized derivative fair value gains/(loss)	**1**	(4)	**2**	(5)
Lakehead System - hydrostatic testing	**-**	-	**-**	12
Lakehead System - leak remediation costs	**-**	(1)	**-**	(21)
Regional Oil Sands System - northeastern Alberta wildfire pipelines and facilities restart cost	**-**	(21)	**-**	(21)
Regional Oil Sands System - make-up rights adjustment[2]	**-**	(20)	**-**	(34)
Regional Oil Sands System - leak insurance recoveries	**-**	-	**3**	5
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value loss	**-**	(1)	**-**	(1)
Mid-Continent and Gulf Coast - make-up rights adjustment[2]	**-**	(28)	**-**	(78)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**9**	(6)	**16**	26
Bakken System - changes in unrealized derivative fair value loss	**(1)**	(2)	**-**	(3)
Bakken System - make-up rights adjustment[2]	**-**	3	**-**	-
Bakken System - gain on sale of pipe and project wind-down costs	**67**	-	**62**	-
Feeder Pipelines and Other - investment impairment loss	**-**	(176)	**-**	(176)
Feeder Pipelines and Other - derecognition of regulatory balances	**-**	(6)	**-**	(6)
Feeder Pipelines and Other - make-up rights adjustment[2]	**-**	(2)	**-**	(2)
Feeder Pipelines and Other - project development and transaction costs	**(3)**	(3)	**(4)**	(3)
Earnings before interest and income taxes	**1,272**	643	**2,396**	2,255

1 *Includes adjusted EBIT from Express-Platte System since the completion of the Merger Transaction on February 27, 2017. For additional information, refer to* Merger with Spectra Energy.

2 *Effective January 1, 2017, the Company no longer makes such an adjustment to its EBIT.*

Additional details on items impacting Liquids Pipelines EBIT include:

- Canadian Mainline EBIT for each period reflects changes in unrealized fair value gains and losses on derivative financial instruments used to manage foreign exchange and commodity price risk inherent within the Competitive Toll Settlement (CTS).

- Southern Lights Pipeline EBIT for each period reflects changes in unrealized fair value gains and losses on derivative financial instruments used to manage foreign exchange risk on United States dollar cash flows from the Southern Lights Class A units.

- Bakken System EBIT for 2017 includes the gain on sale of pipe offset by project wind-down costs related to EEP s Sandpiper Project.

- Feeder Pipelines and Other loss before interest and income taxes for 2016 included impairment charges related to Enbridge s 75% joint venture interest in Eddystone Rail attributable to market conditions that impacted volumes at the rail facility.

Canadian Mainline

Canadian Mainline adjusted EBIT increased in the second quarter of 2017, compared with the corresponding 2016 period, primarily due to a higher Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll and higher average throughput. The Canadian Mainline also benefitted from a higher foreign exchange hedge rate used to record Canadian Mainline revenues. For the second quarter of 2017, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.04, compared with $1.03 for the corresponding 2016 period.

Throughput on the mainline system was affected by unusual events in the second quarter of both 2016 and 2017. In 2016, wildfires in Alberta resulted in a curtailment of production from oil sands facilities and the temporary shutdown of certain of the Company s upstream pipelines and terminal facilities, decreasing second quarter 2016 adjusted EBIT by approximately $30 million. While higher than the second quarter of 2016, throughput in the second quarter of 2017 was affected by a significant unexpected outage and accelerated maintenance at a customer s upstream facility, and additional related and unrelated production disruptions.

The outages experienced in June were temporary and adjusted EBIT on the Canadian Mainline is expected to be positively impacted in the second half of 2017 as throughput returns to levels experienced earlier in the year and apportionment on the system is relieved through capacity optimizations that were implemented in the first half of the year.

Canadian Mainline adjusted EBIT decreased in the first half of 2017, compared with the corresponding 2016 period. Higher adjusted EBIT in the second quarter of 2017, as discussed above, was offset by the lower first quarter results. First quarter results in 2017 decreased, compared with the corresponding 2016 period, due to the absence of hydrostatic test surcharge revenue recognized in 2017, a lower average Canadian Mainline IJT Residual Benchmark Toll and a lower foreign exchange hedge rate used to record United States dollar denominated Canadian Mainline revenues. For the first quarter of 2017, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.04, compared with $1.11 for the corresponding 2016 period.

Supplemental information related to the Canadian Mainline for the three and six months ended June 30, 2017 and 2016, is provided below:

June 30,	**2017**	2016
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.05**	$4.07

Lakehead System Local Toll[2]	**$2.43**	$2.61
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.62**	$1.46

1 *The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2016, this toll decreased to US$4.05. Effective July 1, 2017, this toll increased to US$4.07.*

2 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2016, this toll increased to US$2.61 and effective July 1, 2016, this toll decreased to US$2.58. Effective April 1, 2017, this toll decreased to US$2.43.*

3 *The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll and the Lakehead System Local Toll. Effective April 1, 2016, this toll decreased to US$1.46, coinciding with the revised Lakehead System Local Toll. Effective July 1, 2016, this toll increased to US$1.47. Effective April 1, 2017, this toll increased to US$1.62, coinciding with the revised Lakehead System Local Toll. Effective July 1, 2017, this toll increased to US$1.64.*

Throughput Volume

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(thousands of bpd)				
Average throughput volume1	**2,449**	2,242	**2,521**	2,392

1 Throughput volume represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.

Lakehead System

Lakehead System adjusted EBIT decreased in the second quarter of 2017, compared with the corresponding 2016 period. The second quarter decrease was primarily due to a lower Lakehead System Local Toll, and increased property taxes and depreciation expense resulting from an increased asset base and hydrostatic testing costs in the second quarter of 2017. These negative impacts were partially offset by a higher average United States to Canadian dollar exchange rate (Average Exchange Rate) in the second quarter of 2017, compared with the corresponding 2016 period, and higher average throughput reflecting system optimization.

In addition, the higher average throughput in the second quarter of 2017 compared to 2016 was partially driven by the negative impact of the northeastern Alberta wildfires experienced in 2016. The wildfires resulted in a curtailment of production from oil sands facilities and the temporary shutdown of certain of the Company s upstream pipelines and terminal facilities, decreasing adjusted EBIT by approximately $38 million for the three months ended June 30, 2016. While higher than the second quarter of 2016, throughput in the second quarter of 2017 was affected by a significant unexpected outage and accelerated maintenance at a customer s upstream facility, additional related and unrelated production disruptions, and a hydrostatic testing program on Line 5 during the month of June 2017.

The outages experienced in June were temporary and adjusted EBIT on the Lakehead System is expected to be positively impacted in the second half of 2017 as throughput returns to levels experienced earlier in the year and apportionment on the system is relieved through capacity optimizations that were implemented in the first half of the year.

Lakehead System adjusted EBIT decreased in the first half of 2017, compared with the corresponding 2016 period. The decrease in the second quarter of 2017, as discussed above, was partially offset by higher first quarter results in 2017. Strong operating performance in the first quarter of 2017 was driven by higher long-haul throughput and a higher Lakehead System Local Toll compared to 2016. As discussed under *Canadian Mainline* above, higher throughput on the Lakehead System in the first quarter of 2017 reflected system optimization. It is expected that volumes will increase for the remainder of 2017 as a result of continued optimization efforts.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$222 million and US$516 million for the three and six months ended June 30, 2017, respectively, compared with US$279 million and US$535 million for corresponding 2016 periods.

As noted above, partially offsetting the three and six months ended June 30, 2017 decrease in Lakehead System adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in the second quarter of 2017, compared with the corresponding 2016 period. A portion of Lakehead System United States dollar EBIT is hedged as part of the Company s enterprise-wide financial risk management program. The Company uses foreign exchange derivative instruments to manage the foreign exchange risk arising from its United States businesses including the Lakehead System. Realized gains and losses from these derivative instruments are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Throughput Volume

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(thousands of bpd)				
Average throughput volume[1]	**2,604**	2,440	**2,675**	2,588

1 *Throughput volume represents mainline system deliveries to the United States midwest and eastern Canada.*

Average Exchange Rate

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
Average Exchange Rate (U.S. dollar to Canadian dollar)	**1.34**	1.29	**1.33**	1.33

Mid-Continent and Gulf Coast

Mid-Continent and Gulf Coast adjusted EBIT decreased for the three and six months ended June 30, 2017, compared with the corresponding 2016 period, primarily due to lower contributions from Flanagan South Pipeline (Flanagan South) and the absence of adjusted EBIT from the Ozark Pipeline that was sold in the first quarter of 2017. The decrease in adjusted EBIT was partially offset by a higher Average Exchange Rate in the second quarter of 2017, compared with the corresponding 2016 period.

Adjusted EBIT reported by Flanagan South in the first half of 2017 was impacted by apportionments on the mainline system and by a change in treatment of deferred revenue created by take-or-pay contracts with make-up rights in the determination of adjusted EBIT. When committed shippers on Flanagan South are unable to fulfill their volume commitments due to apportionment, they are provided with temporary relief to make up those volumes during the course of their contracts or the apportioned volumes are added on to the end of the contract term. Due to upstream mainline apportionment, committed shippers on Flanagan South were provided higher apportionment relief in the first half of 2017, compared with the first half of 2016, which resulted in lower contractual cash payments from these shippers. For the purposes of adjusted EBIT, prior to January 1, 2017, the Company reflected contributions from these contracts rateably over the life of the contract, consistent with contractual cash payments under the contract. Effective January 1, 2017, for the purposes of determining adjusted EBIT, the Company discontinued this treatment.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$95 million and US$185 million for the three and six months ended June 30, 2017, respectively, compared with US$125 million and US$257 million for the three and six months ended June 30, 2016.

As noted above, partially offsetting the three and six months ended June 30, 2017 decrease in adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in the second quarter of 2017, compared with the corresponding 2016 period. Similar to Lakehead System, a portion of Mid-Continent and Gulf Coast United States dollar EBIT is hedged as part of the Company s enterprise-wide financial risk management program, and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company s investment in United States businesses are reported within Eliminations and OtherFor further details refer to *Eliminations and Other*.

Express-Platte System

The Express-Platte pipeline system, an approximate 2,736 kilometre (1,700 mile) crude oil transportation system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois, is comprised of both the Express and Platte crude oil pipelines and crude oil storage of approximately 5.6 million barrels. The Express pipeline carries crude oil to United States refining markets in the Rockies area, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with the Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest. The Company has a 75% indirect ownership interest in Express-Platte, through its investment in SEP.

Express capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of Express capacity and all of the Platte capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

Express-Platte is exposed to the same business risks as the Company s other Liquids Pipelines assets as discussed in Enbridge s MD&A for the year ended December 31, 2016.

Results of Operations

Express-Platte adjusted EBIT for the three and six months ended June 30, 2017, reflects results of operations since the completion of the Merger Transaction on February 27, 2017.

When compared to pre-Merger results from the prior year, Express-Platte results include higher crude oil transportation revenues due to higher uncommitted volumes on the Express pipeline, higher tariff rates on the Express pipeline due to annual escalations, and higher volumes from the Express Enhancement expansion project placed into service in October 2016. These higher revenues were partially offset by higher power costs due to higher throughput.

Bakken System

Bakken System adjusted EBIT decreased for the three months ended June 30, 2017, compared with the corresponding 2016 period. The decrease in adjusted EBIT reflected lower rates and lower rail revenues on the United States portion of the Bakken System owned by EEP, partially offset by the positive impact of translating United States dollar earnings to Canadian dollars at a higher Average Exchange Rate in the second quarter of 2017, compared with the corresponding 2016 period.

Bakken System adjusted EBIT decreased for the six months ended June 30, 2017, compared with the corresponding 2016 period, primarily due the three month reasons discussed above.

Excluding the impact of foreign exchange translation to Canadian dollars, Bakken System adjusted EBIT was US$31 million and US$51 million for the three and six months ended June 30, 2017, respectively, compared with US$36 million and US$73 million for the corresponding 2016 periods. The decrease in adjusted EBIT for the three and six months ended June 30, 2017, for the United States portion of the Bakken System was attributable to lower surcharge revenues as certain surcharge rates expired effective December 31, 2016.

As noted above, partially offsetting the three and six months ended June 30, 2017 decrease in adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in the second quarter of 2017, compared with the corresponding 2016 period. Similar to Lakehead System, a part of the United States portion of the Bakken System United States dollar EBIT is hedged under the Company s enterprise-wide financial risk management program, and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company s investment in United States businesses are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted EBIT decreased for the three and six months ended June 30, 2017, compared with the corresponding 2016 periods, reflecting the absence of EBIT from the South Prairie Region assets that were sold in December 2016.

GAS PIPELINES AND PROCESSING

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
US Gas Transmission[1]	**567**	-	**774**	-
Canadian Midstream[2]	**52**	28	**103**	49
Alliance Pipeline	**43**	47	**100**	96
US Midstream[3,4]	**(17)**	5	**(24)**	4
Other[5]	**22**	10	**50**	28
Adjusted earnings before interest and income taxes	**667**	90	**1,003**	177
US Gas Transmission - inspection, repair and other costs	**(14)**	-	**(16)**	-
US Gas Transmission - project development and transaction costs	**(1)**	-	**(3)**	-
Canadian Midstream - project development and transaction costs	**-**	-	**(1)**	-
Canadian Midstream - Grizzly Valley flood	**7**	-	**7**	-
Alliance Pipeline - changes in unrealized derivative fair value gains	**3**	-	**5**	12
US Midstream - changes in unrealized derivative fair value gains/(loss)	**14**	(59)	**22**	(97)
US Midstream - assets impairment loss	**-**	(11)	**-**	(11)
US Midstream - make-up rights adjustment	**-**	(1)	**-**	(1)
Other - DCP Midstream mark-to-market adjustment	**6**	-	**4**	-
Earnings before interest and income taxes	**682**	19	**1,021**	80

1 *Includes adjusted EBIT from US Gas Transmission since the completion of the Merger Transaction on February 27, 2017. For additional information, refer to* Merger with Spectra Energy.

2 *Includes adjusted EBIT from British Columbia Pipeline & Field Services, Spectra Canadian Midstream, Maritimes & Northeast Canada (M&N Canada) and certain other gas pipeline, gathering and storage assets since the completion of the Merger Transaction on February 27, 2017.*

3 *Includes adjusted EBIT from DCP Midstream since the completion of the Merger Transaction on February 27, 2017.*

4 *Effective January 1, 2017, adjusted EBIT from Aux Sable, which is comprised of Enbridge s equity interest in Aux Sable US, Aux Sable Midstream US and Aux Sable Canada, has been grouped with US Midstream. Comparative amounts have been reclassified to facilitate comparison.*

5 *Effective January 1, 2017, adjusted EBIT from Vector Pipeline and Enbridge Offshore Pipelines (Offshore) have been grouped with Other. Comparative amounts have been reclassified to facilitate comparison.*

Additional details on items impacting Gas Pipelines and Processing EBIT include:

- US Midstream EBIT for each period reflects changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage commodity price exposures.

US Gas Transmission

The assets that comprise US Gas Transmission were acquired through the Merger Transaction and consist of natural gas transmission and storage assets that are held through SEP. The following indirect ownership interests are reported in this business segment: 75% of Texas Eastern, 68% of Algonquin, 75% of East Tennessee Natural Gas, 59% of M&N U.S., 38% of Gulfstream, and certain other gas pipeline, gathering and storage assets. The US Gas Transmission business primarily provides transmission, storage and gathering of natural gas through interstate pipeline systems for customers in various regions of the midwestern, northeastern and southern United States and in Canada. Demand on the natural gas pipeline and storage systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth quarters, and storage injections occurring primarily during the summer periods.

The Texas Eastern natural gas transmission system extends approximately 2,735 kilometres (1,700 miles) from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York and includes both onshore and offshore pipelines, compressor stations and three storage facilities. Texas Eastern is also connected to four affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business.

The Algonquin natural gas transmission system connects with Texas Eastern s facilities in New Jersey and extends approximately 402 kilometres (250 miles) through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N U.S. The system consists of approximately 1,819 kilometres (1,130 miles) of pipeline with associated compressor stations.

East Tennessee s natural gas transmission system crosses Texas Eastern s system at two locations in Tennessee and consists of two mainline systems totalling approximately 2,414 kilometres (1,500 miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a LNG storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

M&N U.S., which is owned 78% by Enbridge, is an approximately 563 kilometre (350 mile) mainline interstate natural gas transmission system, including associated compressor stations, which extends from the border of Canada near Baileyville, Maine to northeastern Massachusetts. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system, M&N Canada (see *Gas Pipelines and Processing Canadian Midstream*).

Gulfstream is an approximately 1,199 kilometre (745 mile) interstate natural gas transmission system, with associated compressor stations, operated jointly by SEP and The Williams Companies, Inc. (Williams). Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream is owned 50% directly by SEP and 50% by affiliates of Williams and is accounted for under the equity method of accounting.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines or injected or withdrawn from the Company s storage facilities, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also provided where customers can use capacity if it is available at the time of the request. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this interruptible service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers needs.

Business Risks

The risks identified below are specific to US Gas Transmission. General risks that affect the entire Company are described under *Risk Management and Financial Instruments General Business Risks* in Enbridge s MD&A for the year ended December 31, 2016.

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Asset Utilization

Gas supply and demand dynamics continue to change as a result of the development of non-conventional shale gas supplies. The increase in natural gas supply has resulted in declines in the price of natural gas in North America. As a result, a shift occurred to extraction of gas in richer, wet gas areas with higher NGL content which depressed activity in dry fields. This, in turn, has contributed to a resulting oversupply of pipeline takeaway capacity in some areas.

Seasonal Price Spreads

The supply increase has also had a negative impact on the seasonal price spreads historically seen between the summer and winter months. The value of storage assets and contracts has declined in recent years, negatively affecting the results from the Company s storage facilities.

Economic Regulation

US Gas Transmission is subject to laws and regulations at the federal and state levels. Regulations applicable to the natural gas transmission and storage industries have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and the Company cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on its businesses.

Competition

The US Gas Transmission business competes with similar facilities that serve the same supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service. The natural gas transported in the US Gas Transmission business also competes with other forms of energy available to the Company s customers and end-users, including electricity, coal, propane and fuel oils.

Results of Operations

US Gas Transmission adjusted EBIT for the three and six months ended June 30, 2017, reflected results of operations since the completion of the Merger Transaction on February 27, 2017. When compared to pre-Merger results from the prior year, US Gas Transmission s operating results include higher earnings primarily from business expansion projects on Algonquin Gas Transmission, Sabal Trail Transmission and Texas Eastern Transmission.

Canadian Midstream

Upon completion of the Merger Transaction on February 27, 2017, Canadian Midstream now also includes the Western Canada Transmission & Processing businesses, which comprise British Columbia Pipeline & Field Services, Canadian Midstream, M&N Canada and certain other gas pipeline, gathering and storage assets. British Columbia Pipeline and British Columbia Field Services provide fee-based natural gas transmission and gas gathering and processing services. British Columbia Pipeline has approximately 2,816 kilometres (1,750 miles) of transmission pipeline in British Columbia and Alberta, as well as associated mainline compressor stations. The British Columbia Field Services business includes eight gas processing plants located in British Columbia associated field compressor stations and approximately 2,253 kilometres (1,400 miles) of gathering pipelines. Canadian Midstream provides similar gas gathering and processing services in British Columbia and Alberta and consists of nine natural gas processing plants and approximately 966 kilometres (600 miles) of gathering pipelines. M&N Canada is an approximately 885 kilometre (550 mile) interprovincial natural gas transmission mainline system which extends from Goldboro, Nova Scotia to the United States border near Baileyville, Maine. M&N Canada is connected to M&N U.S. refer to *US Gas Transmission.* Enbridge has an approximate 78% interest in M&N Canada.

The majority of transportation services are provided by British Columbia Pipeline under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. British Columbia Pipeline also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported. Natural gas gathering and processing services are provided under fee-for-service contracts.

Business Risks

The risks identified below are specific to the Western Canada Transmission & Processing businesses. General risks that affect the entire Company are described under *Risk Management and Financial Instruments General Business Risks* in Enbridge s MD&A for the year ended December 31, 2016.

Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, producers and pipelines in the gathering, processing and transmission of natural gas. The principal elements of competition are location, rates, terms of service, and flexibility and reliability of service.

Asset Utilization

Western Canada Transmission & Processing businesses provide services under fee-for-service contracts and its revenues are not directly exposed to commodity price risk. However, the sustained decline in natural gas prices has reduced producer demand for both expansions of the British Columbia gas processing plants as well as renewals of existing gas processing contracts, and this trend could continue if prices remain below historical norms.

Results of Operations

Canadian Midstream adjusted EBIT for the three and six months ended June 30, 2017, reflected the results of operations from the new assets acquired through the Merger Transaction as described above. The three and six months ended June 30, 2017 increase in Canadian Midstream adjusted EBIT also reflected contributions from the Tupper Plants acquired in April 2016.

When compared to pre-Merger results from the corresponding periods in 2016, Canadian Midstream results include a decrease in firm revenue primarily as a result of shipper contract renewals at lower volumes as well as an increase in operating and maintenance costs, partially offset by higher interruptible revenues and incremental revenues from volumes that exceeded take-or-pay levels due to robust producer activity within Canadian Midstream s footprint.

Alliance Pipeline

Alliance Pipeline adjusted EBIT for the three and six months ended June 30, 2017, which comprises equity earnings from the Company s 50% equity investment in Alliance Pipeline, was comparable with the corresponding 2016 periods.

US Midstream

Upon completion of the Merger Transaction on February 27, 2017, US Midstream now also includes a 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers, compresses, treats, processes, transports, stores and sells natural gas. It also produces, fractionates, transports, stores and sells NGLs, recovers and sells condensate, and trades and markets natural gas and NGLs. Phillips 66 owns the other 50% interest in DCP Midstream.

DCP Midstream owns or operates assets in 17 states in the United States including approximately 102,998 kilometres (64,000 miles) of gathering and transmission pipeline, 61 natural gas processing plants and 12 fractionation facilities. In addition, DCP Midstream operates a propane wholesale marketing business and an eight-million barrel propane and butane storage facility in the northeastern United States. DCP Midstream also holds a 33.3% interest in the Sand Hills and Southern Hills NGL pipelines.

DCP Midstream is exposed to similar business risks as the Company s existing US Midstream assets as disclosed in Enbridge s MD&A for the year ended December 31, 2016.

Purchase, Service and Sales Agreements

DCP Midstream sells a portion of its NGLs to Phillips 66 and Chevron Phillips Chemical Company LLC (CPChem). In addition, DCP Midstream purchases NGLs from CPChem. Approximately 26% of DCP Midstream s NGL production was committed to Phillips 66 and CPChem as at June 30, 2017, under contracts expiring in January 2019. DCP Midstream anticipates continuing to purchase and sell commodities with Phillips 66 and CPChem, in the ordinary course of business.

The residual natural gas, primarily methane, that results from processing raw natural gas is sold at market-based prices to marketers and end-users, including large industrial companies, natural gas distribution companies and electric utilities. DCP Midstream purchases or takes custody of substantially all of its raw natural gas from producers, principally under percentage-of-proceeds/index arrangements, keep-whole and wellhead purchase agreements and fee-based arrangements. More than 75% of the volumes of gas that are gathered and processed are under percentage-of-proceeds contracts. Percentage-of-proceeds arrangements typically result in DCP Midstream gathering, processing and selling natural gas that has been purchased from producers. The residue natural gas and NGLs are sold based on index prices from published index market prices. DCP Midstream remits to the producers either an agreed-upon percentage of the actual proceeds received by DCP Midstream or an agreed-upon percentage of the proceeds based on index-related prices or contractual recoveries, regardless of the actual amount of sales proceeds. DCP Midstream s revenues from percentage-of-proceeds/index arrangements are directly related to the prices of natural gas, NGLs or condensate.

Results of Operations

US Midstream incurred a higher adjusted loss before interest and income taxes for the three and six months ended June 30, 2017, compared with the corresponding 2016 periods. The increase in adjusted loss before interest and income taxes for the three and six months ended June 30, 2017, was primarily attributable to lower volumes on the Company s US Midstream assets that are held by MEP, as a result of the continued low commodity price environment which resulted in reduced drilling by producers. Partially offsetting this negative effect was higher contributions from Aux Sable US due to increased fractionation margins, as well as a contribution from the Company s investment in DCP Midstream that was acquired through the Merger Transaction. Post completion of the Merger Transaction, DCP Midstream contributed $23 million and $28 million to US Midstream adjusted EBIT for the three and six months ended June 30, 2017, respectively.

Other

Other adjusted EBIT increased for the three and six months ended June 30, 2017, compared with the corresponding 2016 periods, primarily reflecting positive contributions from Offshore as a result of an increase in transportation rates on Heidelberg Oil Pipeline and an increase in variable rate revenues on Walker Ridge Gas Gathering System.

GAS DISTRIBUTION

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**81**	72	**219**	247
Union Gas Limited (Union Gas)1	**79**	-	**142**	-
Noverco Inc. (Noverco)	**(13)**	(5)	**24**	33
Other Gas Distribution and Storage	**6**	6	**37**	33
Adjusted earnings before interest and income taxes	**153**	73	**422**	313
EGD - (warmer)/colder than normal weather2	**-**	9	**-**	(8)

Noverco - changes in unrealized derivative fair value gains	**-**	1	**10**	-
Noverco - recognition of regulatory balances	**-**	-	**-**	17
Union Gas - employee severance and restructuring costs	**-**	-	**(4)**	-
Earnings before interest and income taxes	**153**	83	**428**	322

1 *Includes adjusted EBIT from Union Gas since the completion of the Merger Transaction on February 27, 2017. For additional information, refer to* Merger with Spectra Energy.

2 *Effective January 1, 2017, the Company no longer adjusts for the impact of weather in the determination of its adjusted EBIT.*

EGD

As EGD s operations are rate-regulated and its revenues are directly impacted by items such as depreciation, financing charges and current income taxes, the adjusted EBIT measure for EGD is less indicative of business performance. In light of the nature of the regulated model for EGD s business, the following supplemental adjusted earnings information is provided to facilitate an understanding of EGD s results from operations:

EGD Earnings

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**81**	72	**219**	247
Interest expense	**(44)**	(44)	**(90)**	(81)
Income taxes	**4**	-	**(6)**	(20)
Adjusting items in respect of:				
Interest expense	**-**	-	**1**	-
Income taxes	**-**	2	**-**	(2)
Adjusted earnings	**41**	30	**124**	144
EGD - (warmer)/colder than normal weather	**-**	7	**-**	(6)
Earnings attributable to common shareholders	**41**	37	**124**	138

EGD adjusted earnings increased in the second quarter of 2017, compared with the corresponding 2016 period, primarily due to lower employee and pension related costs, and higher distribution charges, partially offset by warmer weather.

EGD adjusted earnings decreased in the first half of 2017, compared with the corresponding 2016 period. The increase in the second quarter of 2017, as discussed above, was more than offset by weaker first quarter results. First quarter results in 2017 decreased, compared with the corresponding 2016 period, primarily due to higher earnings sharing in 2017, higher depreciation expense resulting from a higher overall asset base and lower capitalized interest due to the completion of the Greater Toronto Area project in March 2016.

Adjusted earnings for EGD was also lower for the six months ended June 30, 2017, relative to the comparable period in 2016, as a result of a change in practice with respect to weather normalization. Prior to January 1, 2017, the impacts of warmer/colder than normal weather were removed for the purposes of EGD adjusted earnings. Effective January 1, 2017, the Company discontinued this practice, and as such, EGD adjusted earnings reflected lower distribution revenues due to the impacts of warmer than normal weather during the three and six months ended June 30, 2017. If the Company had continued with the above noted weather normalization treatment, EGD adjusted earnings would have increased by $2 million and $23 million, for the three and six months ended June 30, 2017, respectively.

Union Gas

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of operations and service to customers. The distribution business serves approximately 1.5 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas storage and transmission business offers storage and transmission services to customers at the Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from western Canada and United States supply basins to markets in central Canada and the northeast United States.

Union Gas distribution system consists of approximately 64,374 kilometres (40,000 miles) of main and service pipelines. Union Gas underground natural gas storage facilities have a working capacity of approximately 165 billion cubic feet in 25 underground facilities located in depleted gas fields. Its transmission system consists of approximately 4,828 kilometres (3,000 miles) of high pressure pipeline and associated mainline compressor stations.

As with EGD, Union Gas distribution system is regulated by the Ontario Energy Board (OEB) and is subject to regulation in a number of areas, including rates. Union Gas provides its infranchise customers with regulated distribution, transmission and storage services and also provides unregulated natural gas storage and regulated transmission services for other utilities and energy market participants, including large natural gas transmission and distribution companies. A substantial amount of Union Gas annual transportation and storage revenue is generated by fixed demand charges.

Incentive Regulation Framework

Union Gas distribution rates are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation;
- rate increases or decreases in the small volume customer classes where average use declines or increases;
- certain adjustments to rates;
- the continued pass-through of gas commodity, upstream transportation and demand side management costs;
- the additional pass-through of costs associated with major capital investments and certain fuel variances;
- an allowance for unexpected cost changes that are outside of management s control;
- equal sharing of tax changes between Union Gas and customers; and
- an earnings sharing mechanism that permits Union Gas to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers. In October 2016, Union Gas filed an application with the OEB for new rates effective January 1, 2017, pursuant to the incentive regulation framework. In December 2016, the OEB approved the application on an interim basis with an implementation date of January 1, 2017, to be included in the Quarterly Rate Adjustment Mechanism. A final rate order is expected after the OEB completes its review of Union Gas Cap and Trade Compliance Plan.

Cap and Trade

Similar to EGD, Union Gas is subject to the requirements of the Government of Ontario s Cap and Trade program, which became effective January 1, 2017. Refer to *Gas Distribution Enbridge Gas Distribution Inc. Cap and Trade* in Enbridge s MD&A for the year ended December 31, 2016, for more information on this program. In November 2016, Union Gas filed its 2017 Compliance Plan and the OEB issued an interim rate order approving the associated Cap and Trade costs for recovery from customers effective January 1, 2017. The OEB will complete its review of Union Gas 2017 Compliance Plan and approve the final rates in 2017.

Business Risks

Union Gas is subject to substantially the same business risks as Enbridge s other gas distribution assets as disclosed in Enbridge s MD&A for the year ended December 31, 2016.

Results of Operations

Union Gas adjusted EBIT for the three and six months ended June 30, 2017, reflects its results of operations since the completion of the Merger Transaction on February 27, 2017.

Union Gas results benefitted mainly from higher transportation revenue from the Dawn-Parkway expansion project, partially offset by lower usage due to warmer weather in the first half of 2017.

As Union Gas operations are rate-regulated and its revenues are directly impacted by items such as depreciation, financing charges and current income taxes, the adjusted EBIT measure for Union Gas is less indicative of business performance. In light of the nature of the regulated model for Union Gas business, the following supplemental adjusted earnings information is provided to facilitate an understanding of Union Gas results from operations:

Union Gas Earnings[1]

	Three months ended June 30, 2017	Six months ended June 30, 2017
(millions of Canadian dollars)		
Adjusted earnings before interest and income taxes	**79**	**142**
Interest expense	**(41)**	**(56)**
Income taxes	**(4)**	**11**
Adjusting items in respect of:		
Income taxes	**-**	**(1)**
Earnings attributable to noncontrolling interests	**-**	**(1)**
Adjusted earnings	**34**	**95**
Union Gas - Employee severance and restructuring costs	**-**	**(3)**
Earnings attributable to common shareholders	**34**	**92**

1 Includes adjusted earnings generated by Union Gas since the completion of the Merger Transaction on February 27, 2017.

Similar to EGD, Union Gas adjusted earnings for each period include the impact of warmer/colder than normal weather in their franchise area. If Union Gas made an adjustment for warmer than normal weather, adjusted earnings would have increased by $7 million and $9 million, for the three and six months ended June 30, 2017, respectively.

GREEN POWER AND TRANSMISSION

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Green Power and Transmission	**51**	40	**101**	88
Adjusted earnings before interest and income taxes	**51**	40	**101**	88
Green Power and Transmission - changes in unrealized derivative fair value gains	**-**	1	**-**	2
Earnings before interest and income taxes	**51**	41	**101**	90

Green Power and Transmission adjusted EBIT increased for the three and six months ended June 30, 2017, compared with the corresponding 2016 periods. The increase in adjusted EBIT reflected stronger Canadian wind resources in the first half of 2017 and stronger United States wind resources in the second quarter of 2017.

ENERGY SERVICES

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Energy Services	**(3)**	47	**(8)**	48
Adjusted earnings/(loss) before interest and income taxes	**(3)**	47	**(8)**	48
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(15)**	(54)	**146**	(61)
Earnings/(loss) before interest and income taxes	**(18)**	(7)	**138**	(13)

Following are additional details on items impacting Energy Services EBIT:

- Energy Services EBIT for each period reflects changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices on the value of inventory.

Energy Services adjusted EBIT for the three and six months ended June 30, 2017, reflected compressed location and quality differentials in certain markets, lower refinery demand for certain products and fewer opportunities to achieve profitable margins on facilities where the Company holds capacity obligations. Adjusted EBIT from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

ELIMINATIONS AND OTHER

Earnings Before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Operating and administrative	**(38)**	(19)	**(78)**	(34)
Realized foreign exchange derivative loss	**(70)**	(64)	**(142)**	(151)
Other	**15**	-	**22**	16
Adjusted loss before interest and income taxes	**(93)**	(83)	**(198)**	(169)
Changes in unrealized derivative fair value gains	**184**	38	**255**	405
Unrealized intercompany foreign exchange gains/(loss)	**(7)**	5	**(14)**	(55)
Project development and transaction costs	**(46)**	-	**(195)**	-
Employee severance and restructuring costs	**(79)**	(8)	**(204)**	(8)
Earnings/(loss) before interest and income taxes	**(41)**	(48)	**(356)**	173

Items impacting Eliminations and Other EBIT include:

- Project development and transaction costs incurred in 2017 in relation to the Merger Transaction. For additional information, refer to *Merger with Spectra Energy.*

Included in Eliminations and Other adjusted loss before interest and income taxes for the three and six months ended June 30, 2017, was a realized loss of $70 million and $142 million, respectively, compared with $64 million and $151 million for the corresponding 2016 periods. The realized loss related to settlements under the Company s foreign exchange risk management program. The Company targets to hedge 80% or more of anticipated consolidated United States dollar denominated earnings from its United States operations utilizing foreign exchange derivative contracts with the objective of enhancing the predictability of its Canadian dollar earnings.

Supplemental information related to the foreign exchange risk management program for the three and six months ended June 30, 2017 and 2016 is provided below:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of U.S. dollars, except exchange rates)				
Foreign currency derivatives realized - notional amount	**320**	261	**584**	522
Average hedge rate	**1.12**	1.04	**1.09**	1.04
Average Exchange Rate (U.S. dollar to Canadian dollar)	**1.34**	1.29	**1.33**	1.33

As the hedged rate was lower than the Average Exchange Rate in each of the three and six-month periods in 2017 and 2016, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for the three months ended June 30, 2017, was greater than the comparative 2016 period due to a higher notional amount of derivatives, partially offset by a lower unfavourable spread between the Average Exchange Rate and hedged rate. The realized hedge loss for the six months ended June 30, 2017, was less than the comparative 2016 period due to lower unfavourable spread between the Average Exchange Rate and hedged rate. The realized loss in Eliminations and Other partially offsets the positive effect of translating the earnings performance of United States dollar denominated businesses at the Average Exchange Rate which is reflected in the reported EBIT of the applicable business segments.

Realized gains and losses on this hedging program are reported in their entirety within Eliminations and Other as the Company manages the foreign exchange risk of its United States businesses at an enterprise-wide level. Gains and losses arising on settlements of foreign exchange derivatives hedging transactional exposure arising from foreign denominated revenues or expenses within the Company s Canadian businesses are captured at the business level and reported as part of the EBIT of the applicable segment. For example, gains and losses on hedges of the Canadian Mainline s United States denominated revenue are reported as part of the EBIT from Canadian Mainline.

The increase in adjusted loss before interest and income taxes reported within Eliminations and Other reflects higher unallocated corporate costs which primarily results from the Merger Transaction, partially offset by synergies achieved thus far on integration of corporate functions.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge s growth strategy, particularly in light of the significant level of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside Enbridge s control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, the Company actively manages financial plans and funding strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and capital markets issuances, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company targets to maintain liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions sufficient to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets.

The Company s financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and incorporates a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles, EEP, the Fund Group and SEP.

CAPITAL MARKET ACCESS

The Company and its self-funding subsidiaries ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive.

SEP has US$1.8 billion of capital expansion spending planned in 2017, which is expected to be funded through a combination of debt, equity issued primarily through its at the market program and return of capital at the project level.

Bank Credit and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge maintains ready access to funds through securement of committed bank credit facilities and it actively manages its bank funding sources to optimize pricing and ensure flexibility. The following table provides details of the Company s committed credit facilities as at June 30, 2017 and December 31, 2016.

		June 30, 2017		
	Maturity Dates	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge	2018-2022	**6,826**	**5,686**	**1,140**
Enbridge (U.S.) Inc.	2018-2019	**3,805**	**2,216**	**1,589**
EEP	2019-2020	**3,409**	**1,994**	**1,415**
EGD	2018	**1,017**	**684**	**333**
Enbridge Income Fund	2019	**1,500**	**771**	**729**
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**26**	**-**	**26**
Enbridge Pipelines Inc.	2018	**3,000**	**1,105**	**1,895**
Enbridge Southern Lights LP	2018	**5**	**-**	**5**
Spectra Energy Capital, LLC[2]	2021	**1,299**	**-**	**1,299**
Spectra Energy Partners[2]	2021	**3,247**	**1,721**	**1,526**
Westcoast[2]	2021	**400**	**-**	**400**
Union Gas[2]	2021	**700**	**300**	**400**
Total committed credit facilities		**25,234**	**14,477**	**10,757**

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

2 *Committed credit facility acquired as part of the merger with Spectra Energy. For additional information, refer to* Merger with Spectra Energy.

During the second quarter of 2017, the Company completed the following term debt offerings:

- $1.2 billion of unsecured medium-term notes with maturity dates ranging from 2022 to 2044 and fixed interest rates ranging from 3.2% to 4.6%.
- $750 million of unsecured floating rate notes which mature in 2019 and carry an interest rate equal to the three-month banker s acceptance rate plus 59 basis points.
- US$500 million of unsecured floating rate notes which mature in 2020 and carry an interest rate equal to the three-month London Interbank Offered Rate (LIBOR) rate plus 70 basis points.

During the second quarter of 2017, SEP issued US$400 million of unsecured floating rate notes which mature in 2020 and carry an interest rate equal to the three-month LIBOR rate plus 70 basis points.

On July 7, 2017, Enbridge completed an offering of aggregated US$1.4 billion of senior unsecured notes (the Notes). The Notes consisted of two US$700 million tranches with fixed interest rates of 2.9% and 3.7%, and mature in five and 10 years, respectively. Approximately US$1.2 billion of the net proceeds from the Notes were used to pay for the redemption of the tendered notes described below.

On July 14, 2017, Enbridge also completed an offering of US$1.0 billion of fixed-to-floating rate subordinated notes. These notes carry a fixed interest rate of 5.5% for the initial 10 years with a floating rate thereafter. These notes have a maturity of 60 years and are callable after 10 years.

The company also completed the following tender offers. On July 7, 2017, Enbridge and Spectra Energy Capital, LLC (Spectra Capital) completed a cash tender offer to purchase the principal amount of Spectra Capital s outstanding 8.0% senior unsecured notes due 2019. The principal amount tendered and accepted was US$267 million. Spectra Capital paid the consenting note holders an aggregate cash consideration of US$310 million. On July 13, 2017, pursuant to a cash tender offer, Spectra Capital purchased the principal amount of its outstanding senior unsecured notes carrying interest rates ranging from 3.3% to 7.5%, with maturities ranging from one to 21 years. The principal amount tendered and accepted was US$761 million. Spectra Capital paid the consenting note holders an aggregate cash consideration of US$857 million.

During the first quarter of 2017, the Company continued to diversify its access to funding through the establishment of a term credit facility with a syndicate of Asian banks for a total commitment of $239 million. As at June 30, 2017, the Company maintained three term credit facilities with syndicates of Asian banks, which were fully drawn upon and provided a cost-effective source of term debt financing when compared with the cost of term debt financing in the North American public markets available at the time.

In addition to the committed credit facilities noted above, the Company also has $556 million (December 31, 2016 - $335 million) of uncommitted demand credit facilities, of which $148 million (December 31, 2016 - $177 million) were unutilized as at June 30, 2017.

The Company s net available liquidity of $11,783 million as at June 30, 2017, was inclusive of $2,028 million of unrestricted cash and cash equivalents and net of bank indebtedness of $1,002 million as reported on the *Consolidated Statements of Financial Position*.

The Company s credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if the Company were to default on payment or violate certain covenants. As at June 30, 2017, the Company was in compliance with all debt covenants and expects to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled Enbridge to manage its credit profile. The Company actively monitors and manages key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at June 30, 2017, the Company s debt capitalization ratio was 47.9%, compared with 62.1% as at December 31, 2016. The improvement in the ratio reflected an increase in equity as a result of the Merger Transaction.

Following the close of the Merger Transaction, the Company s credit ratings were affirmed as follows:

- DBRS Limited confirmed the Company s issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), and changed their rating outlook from under review with developing implications to stable.

- Moody s Investor Services, Inc. affirmed the Company s issuer rating and senior unsecured debt rating of Baa2, subordinated rating of Ba1, preference share rating of Ba1 and commercial paper rating of P-2, and retained a negative outlook.

- Standard & Poor s Rating Services (S&P) affirmed the Company s corporate credit rating and senior unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed the Company s global overall short-term rating of A-2.

- In June 2017, the Company obtained Fitch long-term issuer default rating and senior unsecured debt rating of BBB+, preference share rating of BBB-, junior subordinated note rating of BBB-, and short-term and commercial paper rating of F2 with a stable rating outlook.

Enbridge s solid investment grade credit ratings are a reflection of the low risk nature of its underlying assets; limited exposure to commodity prices and volume risk; its project execution track record; strong dividend coverage; and substantial standby liquidity. The Company believes that it continues to have ample access to capital markets in both Canada and the United States to adequately fund the execution of its growth capital program.

There are no material restrictions on the Company s cash with the exception of the restricted cash of $100 million, which includes EGD s and Union Gas receipt of cash from the Government of Ontario to fund its Green Investment Fund program. In addition, the Company s restricted cash includes cash collateral and amounts for specific shipper commitments. Cash and cash equivalents held by EEP, the Fund Group and SEP are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and SEP, and monthly for the Fund Group. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

Excluding current maturities of long-term debt, the Company had a negative working capital position as at June 30, 2017. The major contributing factor to the negative working capital position was the ongoing funding of the Company s growth capital program.

To address this negative working capital position, the Company maintains significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As previously noted, as at June 30, 2017, the Company s net available liquidity totalled $11,783 million (December 31, 2016 - $14,274 million). It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

SOURCES AND USES OF CASH

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Operating activities	**2,033**	1,370	**3,710**	3,231
Investing activities	**(2,368)**	(2,080)	**(5,891)**	(3,932)
Financing activities	**531**	230	**2,124**	981
Effect of translation of foreign denominated cash and cash equivalents	**(23)**	2	**(32)**	(38)
Increase/(decrease) in cash and cash equivalents	**173**	(478)	**(89)**	242

Significant sources and uses of cash for the three and six months ended June 30, 2017 and June 30, 2016 are summarized below:

Operating Activities

- The Company s cash flows from operating activities increased by $663 million and $479 million for the three and six months ended June 30, 2017, respectively, relative to the corresponding periods of 2016.

The cash growth delivered by operations reflect operating factors discussed under *Non-GAAP Measures Adjusted EBIT and Non-GAAP Measures Adjusted Earnings*.

- For the three and six months ended June 30, 2017, partially offsetting the increase in cash flows from operating activities are transaction and transition costs in connection with the Merger Transaction, as well as employee severance costs in relation to the Company s enterprise-wide reduction of workforce.

- Changes in operating assets and liabilities included within operating activities were $318 million (2016 - $64 million) for the three months ended June 30, 2017 and $555 million (2016 - $195 million) for the six months ended June 30, 2017. Enbridge s operating assets and liabilities fluctuate in the normal course due to various factors, including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments. In addition, cap and trade regulation in the Province of Ontario went into effect on January 1, 2017, which resulted in recognition of a cap and trade compliance liability within the Gas Distribution segment in the first half of 2017.

Investing Activities

- Cash used in investing activities increased by $288 million and $1,959 million for the three and six months ended June 30, 2017, respectively, relative to the corresponding periods of 2016. The increase was primarily attributable to increased investment in equity investments. During the first half of 2017, the Company paid cash consideration of $2.0 billion (US $1.5 billion) for the acquisition of an interest in the Bakken Pipeline System. In addition, the Company also made an equity investment of $0.5 billion in connection with its 50% interest in the Hohe See Project.

- This increase was also attributable to the Company s continued execution of its growth capital program which is further described in *Growth Projects Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

- Also, during the first half of 2017, the Company s investment in intangible assets in relation to the cap and trade regulation was higher compared with the corresponding 2016 period.

- The above increase in cash usage was partially offset by cash acquired in the Merger Transaction in the first quarter of 2017, as well as proceeds from the disposition of the Ozark Pipeline and Sandpiper assets in the first half of 2017. In the first quarter of 2016, the Company paid a deposit of $54 million in connection with the acquisition of the Tupper Plants. In addition, in the second quarter of 2017, the Company also received a cash reimbursement of capital expenditure from a natural gas producer relating to a suspended pipeline project.

Financing Activities

- Net cash generated from financing activities increased by $301 million and $1,143 million for the three and six months ended June 30, 2017, respectively, relative to the corresponding periods of 2016. During the first half of 2017, the Company issued a series of medium term fixed and floating rate notes, the proceeds of which were primarily used to repay maturing term notes and to finance growth capital programs.

- The increase in cash generated from financing activities also reflected overall higher cash contributions from noncontrolling interests, which now include noncontrolling interests in the assets acquired through the Merger Transaction. The distribution to noncontrolling interests also increased due to the acquired assets; which were offset by the decrease in distributions resulting from the EEP strategic restructuring discussed under *United States Sponsored Vehicle Strategy*.

- The above increases in cash were partially offset by the $227 million paid to acquire all of the outstanding publicly-held common units of MEP during the second quarter of 2017, as well as higher cash received from the issuance of common shares in the first quarter of 2016, as a result of the issuance of 56 million common shares in March 2016.

- Finally, the Company s common share dividend payments increased in the first half of 2017, primarily due to the increase in the common share dividend rate effective March 2017, as well as higher number of common shares outstanding as a result of the issuance of approximately 75 million common shares in 2016 and 691 million common shares issued in connection with the Merger Transaction.

Dividend Reinvestment and Share Purchase Plan

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2017, dividends declared were $1,003 million (2016 - $492 million), of which $659 million (2016 - $281 million) were paid in cash and reflected in financing activities. The remaining $344 million (2016 - $211 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the six months ended June 30, 2017, dividends declared were $1,551 million (2016 - $952 million), of which $1,013 million (2016 - $557 million) were paid in cash and reflected in financing activities. The remaining $538 million (2016 - $395 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and six months ended June 30, 2017, 34.3% (2016 42.9%) and 34.7% (2016 41.5%), respectively, of total dividends declared were reinvested.

On August 2, 2017, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2017, to shareholders of record on August 15, 2017.

Common Shares	$0.61000
Preference Shares, Series A	$0.34375
Preference Shares, Series B[1]	$0.21340
Preference Shares, Series C[2]	$0.18600
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J[3]	US$0.30540
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500
Preference Shares, Series 17	$0.32188

1 The quarterly dividend amount of Series B was reset to $0.21340 from $0.25000 on June 1, 2017, due to reset on every fifth anniversary thereafter.

2 The quarterly dividend amount of Series C was set at $0.18600 on June 1, 2017, due to reset on a quarterly basis thereafter.

3 The quarterly dividend amount of Series J was reset to US$0.30540 from US$0.25000 on June 1, 2017, due to reset on every fifth anniversary thereafter.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Disposition of Ozark Pipeline Asset

As noted previously under *Asset Monetization*, on March 1, 2017, the Company sold the Ozark Pipeline to a subsidiary of MPLX LP for cash proceeds of approximately $0.3 billion (US$0.2 billion) including reimbursement of certain costs. The Ozark Pipeline, a non-core asset owned by EEP, transports crude oil from Cushing, Oklahoma to Wood River, Illinois, where it delivers to a third-party refinery and interconnects with other third-party pipelines. Results of operations from the Ozark Pipeline for the period prior to its sales are reported within *Liquids Pipelines Mid-Continent and Gulf Coast*.

Renewal of Line 5 Easement

On January 4, 2017, the Tribal Council of the Bad River Band of Lake Superior Tribe of Chippewa Indians (the Band) issued a press release indicating that the Band had passed a resolution not to renew its interest in certain Line 5 easements through the Bad River Reservation. Line 5 is included within the Company s mainline system. The Band s resolution calls for decommissioning and removal of the pipeline from all Bad River tribal lands and watershed and could impact the Company s ability to operate the pipeline on the Reservation. Since the Band passed the resolution, the parties have agreed to ongoing discussions with the objective of understanding and resolving the Band s concerns on a long-term basis.

Eddystone Rail Legal Matter

In February 2017, Enbridge subsidiary Eddystone Rail filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania. Eddystone Rail alleges that the defendants transferred valuable assets from Eddystone Rail s counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone Rail. Eddystone Rail is seeking payment of compensatory and punitive damages in excess of US$140 million. Eddystone Rail s chances of success in connection with the above noted action cannot be predicted and it is possible that Eddystone Rail may not recover any of the amounts sought. In March 2017, the defendants filed motions to dismiss on all counts. On July 19, 2017, the defendants motions to dismiss were denied and Eddystone Rail s action will therefore be allowed to proceed. Results of operations from Eddystone Rail are reported within *Liquids Pipelines Feeder Pipelines and Other*.

Dakota Access Pipeline

As noted previously under *United States Sponsored Vehicle Strategy Finalization of Bakken Pipeline System Joint Funding Agreement,* the Company s investment in the Bakken Pipeline System is inclusive of the Dakota Access Pipeline. On February 9, 2017, the Standing Rock Sioux nation filed a lawsuit with the US District Court of Appeals (Court) contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline. The Standing Rock Sioux nation is requesting the Court to order the operator to shut down the pipeline until the appropriate regulatory process is completed.

On June 14, 2017, the Court ruled that the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Standing Rock Sioux nation and ordered the Army Corps to reconsider those components of its environmental analysis. The Court did not rule on whether or not the Dakota Access Pipeline should cease operations, but on June 21, 2017, the

Court established a briefing schedule pursuant to which the parties to the litigation will be provided with an opportunity to submit written arguments on this issue. Final briefs must be filed by the parties in late August 2017, but it is not known when the Court will issue its ruling. However, the Dakota Access Pipeline continues to operate pending the Court s decision on this issue.

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 System was reported near Marshall, Michigan.

As at June 30, 2017, EEP s cumulative 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 June 30, 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.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. As at June 30, 2017, 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. One action or claim is 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 this case, the Company does not expect the outcome of this action to be material to its results of operations or financial condition.

Line 6B Fines and Penalties

As at June 30, 2017, EEP s total estimated costs related to the Line 6B crude oil release include US$69 million in fines and penalties, which includes fines and penalties from the Department of Justice as discussed below.

Consent Decree

On May 23, 2017, the United States District Court for the Western District of Michigan, Southern Division, approved the Consent Decree. 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 Lines 6A and 6B crude oil releases. On June 15, 2017, Enbridge made a total payment of US$68 million as required by the Consent Decree, which reflects US$61 million for the civil penalty for the Line 6B release, US$1 million for the Line 6A release, and US$6 million for past removal costs and interest.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011 and refiled in December 2014. Several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On December 1, 2016, the Administrative Law Judge (ALJ) issued its decision which concluded that the Commission should grant the application of Seaway Pipeline for authority to charge market-based rates. The parties filed briefs during the first quarter of 2017 to defend the ALJ s decision and to respond to criticisms of that decision. The Commissioners will now review the entire record and issue a decision. There is no timeline for the FERC to act and issue a decision.

GAS PIPELINES AND PROCESSING

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) 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 September 2014 NFOV, Aux Sable discovered what it believed to be an exceedance of currently permitted limits for Volatile Organic Material. In April 2015, a second NFOV from the EPA was received in connection with this potential exceedance. Aux Sable engaged in discussions with the EPA to evaluate the impacts and ultimate resolution of these issues, including with respect to a draft Consent Decree. Those discussions are continuing and the Consent Decree, when finalized, is not expected to have a material impact on the Company s consolidated financial position or results of operations.

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim. While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on the Company s consolidated financial position or results of operations.

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $4,588 million which are expected to be paid over the next five years.

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.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage 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 are 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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.5%.

As a result of the Merger Transaction, the Company is exposed to changes in the fair value of the fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used to hedge against the future changes to the fair value of the fixed rate debt. The Company has implemented a program to significantly mitigate the impact of fluctuations in the fair value of the fixed rate debt via execution of 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 term 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 3.8%.

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of its ownership 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.

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 GHG compliance obligations. Similar to the gas supply procurement framework, the 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 share units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

THE EFFECT OF DERIVATIVE INSTRUMENTS ON THE STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**3**	2	**1**	(33)
Interest rate contracts	**(41)**	(428)	**(55)**	(1,004)
Commodity contracts	**(9)**	(18)	**12**	(2)
Other contracts	**(6)**	6	**(15)**	37
Net investment hedges				
Foreign exchange contracts	**65**	(12)	**73**	72
	12	(450)	**16**	(930)
Amount of (gain)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(102)**	(1)	**(101)**	2
Interest rate contracts[2]	**36**	72	**84**	51
Commodity contracts[3]	**(2)**	2	**(4)**	(6)
Other contracts[4]	**4**	(4)	**13**	(30)
	(64)	69	**(8)**	17
Amount of (gain)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**4**	5	**6**	31
	4	5	**6**	31
Amount of gain/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**434**	28	**707**	1,044
Interest rate contracts[2]	**32**	4	**14**	8
Commodity contracts[3]	**19**	(114)	**182**	(298)
Other contracts[4]	**(5)**	5	**(5)**	11
	480	(77)	**898**	765

1 Reported within Transportation and other services revenues and Other income/(expense) 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.

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 and six months ended June 30, 2017, the Company recognized an unrealized gain of $3 million and $1 million (2016 - nil) on the derivative and an unrealized loss of $3 million and $1 million (2016 - nil) on the hedged item in earnings. The difference in the amounts, if any, represents hedge ineffectiveness.

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, as discussed under *Liquidity and Capital Resources*. 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. The Company was deemed to be in compliance with all the terms and conditions of its committed credit facilities as at June 30, 2017.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk 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 generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. 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.

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 EGD and Union Gas, credit risk is mitigated by the utilities 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.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Simplifying the Measurement of Goodwill Impairment

Effective January 1, 2017, the Company early adopted Accounting Standards Update (ASU) 2017-04 and applied the standard on a prospective basis. Under the new guidance, goodwill impairment will now be measured by the amount by which a reporting unit s carrying value exceeds its fair value; this amount should not exceed the carrying amount of goodwill. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Clarifying the Definition of a Business in an Acquisition

Effective January 1, 2017, the Company early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Accounting for Intra-Entity Asset Transfers

Effective January 1, 2017, the Company early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting

Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Simplifying the Embedded Derivatives Analysis for Debt Instruments

Effective January 1, 2017, the Company adopted ASU 2016-06 on a modified retrospective basis. The new guidance simplifies the embedded derivative analysis for debt instruments containing contingent call or put options. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective for annual periods beginning after December 15, 2017 and is to be applied on a prospective basis. The adoption of ASU 2017-09 is not expected to have a material impact on the Company s consolidated financial statements.

Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium

ASU 2017-08 was issued in March 2017 with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied on a modified retrospective basis.

Improving the Presentation of Net Periodic Benefit Cost Related to Defined Benefit Plans

ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity s sponsored defined benefit pension and other postretirement plans. In addition, only the service-cost component of net benefit cost is eligible for capitalization. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2017 and is to be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. Other than the revised statement of earnings presentation, the adoption of ASU 2017-07 is not expected to have a material impact on the Company s consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets

ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2017, and is to be applied on a retrospective or modified retrospective basis.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model, that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019 and is to be applied using a modified retrospective approach.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

Revenue from Contracts with Customers

ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has tentatively decided to adopt the new revenue standard using the modified retrospective method.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company s initial assessment, the application of the standard may result in a change in presentation in the Gas Distribution business related to payments to customers under the earnings sharing mechanism which, are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. Additionally, estimates of variable consideration which will be required under the new standard for certain Liquids Pipelines, Gas Pipelines and Processing and Green Power and Transmission revenue contracts as well as the allocation of the transaction price for certain Liquids Pipelines revenue contracts, may result in changes to the pattern or timing of revenue recognition for those contracts. While the Company has not yet completed the assessment, the Company s preliminary view is that it does not expect these changes will have a material impact on revenue or earnings/(loss). The Company is currently developing processes to generate the disclosures required under the new standard.

QUARTERLY FINANCIAL INFORMATION

	2017		2016				2015	
	Q2[2]	**Q1[2]**	Q4	Q3	Q2	Q1	Q4	Q3
(millions of Canadian dollars, except per share amounts)								
Revenues	**11,116**	**11,146**	9,338	8,488	7,939	8,795	8,914	8,320
Earnings/(loss) attributable to common shareholders	**919**	**638**	365	(103)	301	1,213	378	(609)
Earnings/(loss) per common share	**0.56**	**0.54**	0.39	(0.11)	0.33	1.38	0.44	(0.72)
Diluted earnings/(loss) per common share	**0.56**	**0.54**	0.39	(0.11)	0.33	1.38	0.44	(0.72)
Dividends per common share	**0.610**	**0.583**	0.530	0.530	0.530	0.530	0.465	0.465
Changes in unrealized derivative fair value (gains)/loss[1]	**(537)**	**(245)**	189	32	1	(652)	45	654

1 *Included in earnings/(loss) attributable to common shareholders.*

2 *Included in the first and second quarters of 2017 were the results of operations from the assets acquired through the Merger Transaction effective February 27, 2017. For additional information, refer to* Merger with Spectra Energy, Liquids Pipelines, Gas Pipelines and Processing, Gas Distribution, as well as Eliminations and Other.

Several factors impact comparability of the Company s financial results on a quarterly basis, including, but not limited to, the Merger Transaction in the first quarter of 2017, seasonality in the Company s gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

A significant part of the Company s revenues is generated from its energy services operations. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices. Commodity prices do not directly impact earnings since these earnings reflect a margin or percentage of revenues that depends more on differences in commodity prices between locations and points in time than on the absolute level of prices.

The Company actively manages its exposure to market risks including, but not limited to, commodity prices, interest rates and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, changes in unrealized fair value gains and losses on these instruments will impact earnings.

In addition to the impacts of the Merger Transaction, as well as the changes in unrealized gains and losses outlined above, significant items impacting the consolidated quarterly earnings are noted below:

- Included in the first quarter of 2017 were charges to earnings of $152 million ($111 million after-tax) with respect to costs incurred in relation to the Merger Transaction, as well as $129 million ($92 million after-tax) of employee severance costs in relation to the Company s enterprise-wide reduction of workforce in March 2017 and restructuring costs in connection with the completion of the Merger Transaction.

- Included in the fourth quarter of 2016 were employee severance and restructuring costs incurred in relation to the Company s Building Our Energy Future initiative, with a net charge to earnings of $37 million. For additional information on this initiative, refer to the Company s 2016 annual MD&A.

- Included in the fourth quarter of 2016 was a gain of $520 million (after-tax attributable to Enbridge) on the disposal of South Prairie Region assets within the Liquids Pipelines segment.

- Included in the fourth quarter of 2016 was an asset impairment charge of $272 million (after-tax attributable to Enbridge) related to the Northern Gateway Project within the Liquids Pipelines segment.

- Included in the fourth quarter of 2016 and second quarter of 2015 were the tax impacts of asset transfers between entities under common control of Enbridge. The intercompany gains realized by the selling entities have been eliminated from the Company s consolidated financial statements. However, as the transaction involved the sale of partnership units, the tax consequences remained in consolidated earnings and resulted in charges of $11 million and $39 million, respectively.

- In the third quarter of 2016, impairment charges of $1,000 million ($81 million after-tax attributable to Enbridge), including related project costs of $8 million, were recognized in relation to EEP s Sandpiper Project. In the fourth quarter of 2016, additional project costs of $4 million (nil after-tax attributable to Enbridge) were recognized.

- Included in the second and third quarters of 2016 were after-tax costs attributable to Enbridge of $12 million and $10 million, respectively, incurred in relation to the restart of certain of Enbridge s pipelines and facilities following the northeastern Alberta wildfires.

- Included in the second quarter of 2016 were impairment charges of $103 million (after-tax attributable to Enbridge) related to Enbridge s 75% joint venture interest in Eddystone Rail, attributable to market conditions that impacted volumes at the rail facility.

- Included in the fourth quarter of 2015 were employee severance costs in relation to the Company s enterprise-wide reduction of workforce, with a net charge of $25 million to earnings.

- Included in the fourth quarter of 2015 was an asset impairment charge of US$63 million ($11 million after-tax attributable to Enbridge) related to EEP s Berthold rail facility due to the inability to renew committed shipper agreements beyond 2016 or secure sufficient spot volume.

- Included in the third quarter of 2015 were impacts from the transfer of assets between entities under common control of Enbridge in connection with the transfer of Enbridge s Canadian Liquids Pipelines business and certain Canadian renewable energy assets to EIPLP in which the Fund has an indirect interest, resulting in a $247 million loss on the de-designation of interest rate hedges, an $88 million write-off of a regulatory asset in respect of taxes and $16 million of transaction costs.

- Included in the third quarter of 2015 was an after-tax gain of $44 million on the disposal of non-core assets within the Liquids Pipelines segment.

Finally, the Company is in the midst of a substantial growth capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company s capital expansion initiatives, including construction commencement and expected in-service dates, are listed under *Growth Projects Commercially Secured Projects*.

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

	Number	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	18,269,812	June 1, 2022	Series C
Preference Shares, Series C	1,730,188	June 1, 2022	Series B
Preference Shares, Series D	18,000,000	March 1, 2018	Series E
Preference Shares, Series F	20,000,000	June 1, 2018	Series G
Preference Shares, Series H	14,000,000	September 1, 2018	Series I
Preference Shares, Series J	8,000,000	June 1, 2022	Series K
Preference Shares, Series L	16,000,000	September 1, 2017	Series M
Preference Shares, Series N	18,000,000	December 1, 2018	Series O
Preference Shares, Series P	16,000,000	March 1, 2019	Series Q
Preference Shares, Series R	16,000,000	June 1, 2019	Series S
Preference Shares, Series 1	16,000,000	June 1, 2018	Series 2
Preference Shares, Series 3	24,000,000	September 1, 2019	Series 4
Preference Shares, Series 5	8,000,000	March 1, 2019	Series 6
Preference Shares, Series 7	10,000,000	March 1, 2019	Series 8
Preference Shares, Series 9	11,000,000	December 1, 2019	Series 10
Preference Shares, Series 11	20,000,000	March 1, 2020	Series 12
Preference Shares, Series 13	14,000,000	June 1, 2020	Series 14
Preference Shares, Series 15	11,000,000	September 1, 2020	Series 16
Preference Shares, Series 17	30,000,000	March 1, 2022	Series 18

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	1,645,812,740
Stock Options - issued and outstanding (24,755,721 vested)	39,771,613

1 Outstanding share data information is provided as at July 21, 2017.

2 All preference shares are non-voting equity shares. Preference Shares, Series A may be redeemed any time at the Company s option. For other series of Preference Shares, the Company may, at its option, redeem all or a portion of 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 On June 1, 2017, 1,730,188 of Series B fixed rate Preference Shares were converted to Series C floating rate Preference Shares based upon preference share holder elections under the terms of the Series B Preference Shares. No series J Preference Shares were converted on the June 1, 2017 conversion option date.

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

June 30, 2017

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**6,620**	5,470	**13,486**	10,274
Gas distribution sales	**847**	504	**2,210**	1,511
Transportation and other services	**3,649**	1,965	**6,566**	4,949
	11,116	7,939	**22,262**	16,734
Expenses				
Commodity costs	**6,489**	5,303	**13,039**	10,014
Gas distribution costs	**429**	284	**1,444**	1,038
Operating and administrative	**1,646**	1,003	**3,197**	2,100
Depreciation and amortization	**868**	555	**1,540**	1,114
	9,432	7,145	**19,220**	14,266
	1,684	794	**3,042**	2,468
Income/(loss) from equity investments	**236**	(37)	**472**	189
Other income/(expense)	**179**	(26)	**214**	250
Interest expense	**(565)**	(369)	**(1,051)**	(781)
	1,534	362	**2,677**	2,126
Income tax expense *(Note 12)*	**(293)**	(10)	**(491)**	(427)
Earnings	**1,241**	352	**2,186**	1,699
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(241)**	20	**(465)**	(41)
Earnings attributable to Enbridge Inc.	**1,000**	372	**1,721**	1,658
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Earnings attributable to Enbridge Inc. common shareholders	**919**	301	**1,557**	1,514
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 4)*	**0.56**	0.33	**1.11**	1.69
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 4)*	**0.56**	0.33	**1.10**	1.67

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(unaudited; millions of Canadian dollars)				
Earnings	**1,241**	352	**2,186**	1,699
Other comprehensive income/(loss), net of tax				
Change in unrealized loss on cash flow hedges	**(85)**	(234)	**(87)**	(677)
Change in unrealized gain/(loss) on net investment hedges	**171**	(23)	**220**	371
Other comprehensive income/(loss) from equity investees	**2**	1	**8**	(1)
Reclassification to earnings of loss on cash flow hedges	**66**	26	**107**	25
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**3**	7	**7**	9
Foreign currency translation adjustments	**(1,443)**	61	**(1,011)**	(1,316)
Other comprehensive loss, net of tax	**(1,286)**	(162)	**(756)**	(1,589)
Comprehensive income/(loss)	**(45)**	190	**1,430**	110
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**15**	70	**(359)**	170
Comprehensive income/(loss) attributable to Enbridge Inc.	**(30)**	260	**1,071**	280
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(111)**	189	**907**	136

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Six months ended June 30,	
	2017	2016
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares		
Balance at beginning and end of period	**7,255**	6,515
Common shares		
Balance at beginning of period	**10,492**	7,391
Common shares issued	**-**	2,241
Common shares issued in Merger Transaction *(Note 5)*	**37,429**	-
Dividend reinvestment and share purchase plan	**538**	395
Shares issued on exercise of stock options	**45**	25
Balance at end of period	**48,504**	10,052
Additional paid-in capital		
Balance at beginning of period	**3,399**	3,301
Stock-based compensation	**51**	30
Fair value of outstanding earned stock-based compensation from Merger Transaction *(Note 5)*	**77**	-
Options exercised	**(53)**	(12)
Enbridge Energy Company, Inc. common control transaction	**118**	-
Dilution loss on Enbridge Energy Partners, L.P. issuance of A units	**(870)**	-
Dilution gains and other	**357**	98
Balance at end of period	**3,079**	3,417
Retained earnings/(deficit)		
Balance at beginning of period	**(716)**	142
Earnings attributable to Enbridge Inc.	**1,721**	1,658
Preference share dividends	**(164)**	(144)
Common share dividends declared	**(1,551)**	(952)
Dividends paid to reciprocal shareholder	**15**	13
Redemption value adjustment attributable to redeemable noncontrolling interests	**189**	(604)
Adjustment for the recognition of unutilized tax deductions for stock-based compensation expense	**41**	-
Adjustment relating to equity method investment	**-**	(30)
Balance at end of period	**(465)**	83
Accumulated other comprehensive income *(Note 9)*		
Balance at beginning of period	**1,058**	1,632
Other comprehensive loss attributable to Enbridge Inc. common shareholders, net of tax	**(650)**	(1,378)
Balance at end of period	**408**	254
Reciprocal shareholding		
Balance at beginning of period	**(102)**	(83)
Issuance of treasury stock	**-**	(19)
Balance at end of period	**(102)**	(102)
Total Enbridge Inc. shareholders equity	**58,679**	20,219
Noncontrolling interests		
Balance at beginning of period	**577**	1,300
Earnings attributable to noncontrolling interests	**371**	22
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	**(19)**	(146)
Foreign currency translation adjustments	**(112)**	(55)
Reclassification to earnings of loss on cash flow hedges	**23**	16
	(108)	(185)
Comprehensive income/(loss) attributable to noncontrolling interests	**263**	(163)
Noncontrolling interests resulting from Merger Transaction	**8,792**	-
Enbridge Energy Company, Inc. common control transaction	**(331)**	-
Distributions	**(386)**	(362)

Contributions	**453**	28
Dilution gain on Enbridge Energy Partners, L.P. issuance of A units	**870**	-
Other	**13**	(6)
Balance at end of period	**10,251**	797
Total equity	**68,930**	21,016
Dividends paid per common share	**1.193**	1.060

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**1,241**	352	**2,186**	1,699
Adjustments to reconcile earnings to net cash provided by operating activities:				
Depreciation and amortization	**868**	555	**1,540**	1,114
Deferred income taxes (recovery)/expense	**255**	(26)	**416**	348
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 11)*	**(480)**	77	**(898)**	(765)
Earnings from equity investments	**(236)**	(134)	**(472)**	(364)
Distributions from equity investments	**299**	177	**513**	367
Impairment	**-**	187	**-**	187
Gain on disposition	**(69)**	-	**(83)**	-
Hedge ineffectiveness *(Note 11)*	**-**	5	**1**	31
Inventory revaluation allowance	**9**	10	**16**	178
Unrealized intercompany foreign exchange (gain)/loss	**8**	(5)	**14**	55
Other	**(81)**	85	**17**	172
Changes in environmental liabilities, net of recoveries	**(99)**	23	**(95)**	14
Changes in operating assets and liabilities	**318**	64	**555**	195
Net cash provided by operating activities	**2,033**	1,370	**3,710**	3,231
Investing activities				
Capital expenditures	**(2,280)**	(1,314)	**(3,922)**	(2,959)
Joint venture financing	**5**	5	**(34)**	(5)
Long-term investments	**(249)**	(114)	**(2,760)**	(247)
Distributions from equity investments in excess of cumulative earnings	**28**	-	**39**	-
Restricted long-term investments	**(18)**	(16)	**(33)**	(28)
Additions to intangible assets	**(230)**	(29)	**(463)**	(56)
Acquisition *(Note 5)*	**-**	(485)	**-**	(539)
Cash acquired in Merger Transaction *(Note 5)*	**-**	-	**614**	-
Proceeds from disposition	**153**	-	**442**	-
Reimbursement of capital expenditures	**212**	-	**212**	-
Affiliate loans, net	**(5)**	(117)	**(7)**	(115)
Changes in restricted cash	**16**	(10)	**21**	17
Net cash used in investing activities	**(2,368)**	(2,080)	**(5,891)**	(3,932)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**443**	(103)	**703**	140
Net change in commercial paper and credit facility draws	**(82)**	758	**2,203**	(406)
Debenture and term note issues, net of issue costs	**3,175**	-	**3,175**	-
Debenture and term note repayments	**(2,612)**	(423)	**(3,112)**	(423)
Purchase of interest in consolidated subsidiary	**(227)**	-	**(227)**	-
Contributions from noncontrolling interests	**238**	12	**453**	28
Distributions to noncontrolling interests	**(195)**	(178)	**(386)**	(362)
Contributions from redeemable noncontrolling interests	**589**	563	**600**	567
Distributions to redeemable noncontrolling interests	**(63)**	(53)	**(117)**	(95)
Common shares issued	**5**	6	**9**	2,233
Preference share dividends	**(81)**	(71)	**(164)**	(144)
Common share dividends	**(659)**	(281)	**(1,013)**	(557)
Net cash provided by financing activities	**531**	230	**2,124**	981
Effect of translation of foreign denominated cash and cash equivalents	**(23)**	2	**(32)**	(38)
Increase/(decrease) in cash and cash equivalents	**173**	(478)	**(89)**	242
Cash and cash equivalents at beginning of period	**1,855**	1,735	**2,117**	1,015
Cash and cash equivalents at end of period	**2,028**	1,257	**2,028**	1,257

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2017	December 31, 2016
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**2,028**	2,117
Restricted cash	**100**	68
Accounts receivable and other	**5,734**	4,978
Accounts receivable from affiliates	**36**	14
Inventory	**1,249**	1,233
	9,147	8,410
Property, plant and equipment, net	**99,462**	64,284
Long-term investments	**14,321**	6,836
Restricted long-term investments	**237**	90
Deferred amounts and other assets	**6,098**	3,113
Intangible assets, net	**4,061**	1,573
Goodwill	**34,581**	78
Deferred income taxes	**1,129**	1,170
Assets held for sale	**-**	278
Total assets	**169,036**	85,832
Liabilities and equity		
Current liabilities		
Bank indebtedness	**1,002**	623
Short-term borrowings	**975**	351
Accounts payable and other	**7,539**	7,295
Accounts payable to affiliates	**131**	122
Interest payable	**593**	333
Environmental liabilities	**43**	142
Current portion of long-term debt	**2,607**	4,100
	12,890	12,966
Long-term debt	**62,081**	36,494
Other long-term liabilities	**6,939**	4,981
Deferred income taxes	**14,484**	6,036
	96,394	60,477
Contingencies *(Note 15)*		
Redeemable noncontrolling interests	**3,712**	3,392
Equity		
Share capital		
Preference shares	**7,255**	7,255
Common shares *(1,645 and 943 outstanding at June 30, 2017 and December 31, 2016, respectively)*	**48,504**	10,492
Additional paid-in capital	**3,079**	3,399
Deficit	**(465)**	(716)
Accumulated other comprehensive income *(Note 9)*	**408**	1,058
Reciprocal shareholding	**(102)**	(102)
Total Enbridge Inc. shareholders equity	**58,679**	21,386
Noncontrolling interests	**10,251**	577
	68,930	21,963
Total liabilities and equity	**169,036**	85,832
Variable Interest Entities (Note 6)		

See accompanying notes to the interim consolidated financial statements.

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NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. They do not include all of the information and notes required by U.S. GAAP for annual consolidated financial statements and should therefore be read in conjunction with the Company s audited consolidated financial statements and notes for the year ended December 31, 2016. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, necessary to present fairly the Company s financial position, results of operations and cash flows for the interim periods reported. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company s annual consolidated financial statements for the year ended December 31, 2016, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

The Company s operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility businesses, as well as other factors such as the supply of and demand for crude oil and natural gas, and may not be indicative of annual results.

2. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Simplifying the Measurement of Goodwill Impairment

Effective January 1, 2017, the Company early adopted Accounting Standards Update (ASU) 2017-04 and applied the standard on a prospective basis. Under the new guidance, goodwill impairment will now be measured by the amount by which a reporting unit s carrying value exceeds its fair value; this amount should not exceed the carrying amount of goodwill. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Clarifying the Definition of a Business in an Acquisition

Effective January 1, 2017, the Company early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Accounting for Intra-Entity Asset Transfers

Effective January 1, 2017, the Company early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting

Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Simplifying the Embedded Derivatives Analysis for Debt Instruments

Effective January 1, 2017, the Company adopted ASU 2016-06 on a modified retrospective basis. The new guidance simplifies the embedded derivative analysis for debt instruments containing contingent call or put options. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share-based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective for annual periods beginning after December 15, 2017 and is to be applied on a prospective basis. The adoption of ASU 2017-09 is not expected to have a material impact on the Company s consolidated financial statements.

Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium

ASU 2017-08 was issued in March 2017 with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied on a modified retrospective basis.

Improving the Presentation of Net Periodic Benefit Cost Related to Defined Benefit Plans

ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity s sponsored defined benefit pension and other postretirement plans. In addition, only the service-cost component of net benefit cost is eligible for capitalization. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2017 and is to be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. Other than the revised statement of earnings presentation, the adoption of ASU 2017-07 is not expected to have a material impact on the Company s consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets

ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning after December 15, 2017, and is to be applied on a retrospective or modified retrospective basis.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model, that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019 and is to be applied using a modified retrospective approach.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

Revenue from Contracts with Customers

ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has tentatively decided to adopt the new revenue standard using the modified retrospective method.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company s initial assessment, the application of the standard may result in a change in presentation in the Gas Distribution business related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. Additionally, estimates of variable consideration which will be required under the new standard for certain Liquids Pipelines, Gas Pipelines and Processing and Green Power and Transmission revenue contracts as well as the allocation of the transaction price for certain Liquids Pipelines revenue contracts, may result in changes to the pattern or timing of revenue recognition for those contracts. While the Company has not yet completed the assessment, the Company s preliminary view is that it does not expect these changes will have a material impact on revenue or earnings/(loss). The Company is currently developing processes to generate the disclosures required under the new standard.

3. SEGMENTED INFORMATION

Three months ended June 30, 2017	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,243**	**1,954**	**1,022**	**140**	**5,855**	**(98)**	**11,116**
Commodity and gas distribution costs	**(5)**	**(703)**	**(452)**	**2**	**(5,862)**	**102**	**(6,918)**
Operating and administrative	**(684)**	**(553)**	**(241)**	**(41)**	**(11)**	**(116)**	**(1,646)**
Depreciation and amortization	**(385)**	**(250)**	**(157)**	**(50)**	**(1)**	**(25)**	**(868)**
	1,169	**448**	**172**	**51**	**(19)**	**(137)**	**1,684**
Income/(loss) from equity investments	**108**	**155**	**(23)**	**-**	**-**	**(4)**	**236**
Other income/(expense)	**(5)**	**79**	**4**	**-**	**1**	**100**	**179**
Earnings/(loss) before interest and income taxes	**1,272**	**682**	**153**	**51**	**(18)**	**(41)**	**2,099**
Interest expense							**(565)**
Income tax expense							**(293)**
Earnings							**1,241**
Capital expenditures1	**540**	**1,374**	**309**	**115**	**1**	**9**	**2,348**

Three months ended June 30, 2016	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	1,743	615	613	122	4,933	(87)	7,939
Commodity and gas distribution costs	(3)	(463)	(293)	2	(4,917)	87	(5,587)
Operating and administrative	(663)	(127)	(144)	(37)	(19)	(13)	(1,003)
Depreciation and amortization	(336)	(75)	(84)	(47)	(1)	(12)	(555)
	741	(50)	92	40	(4)	(25)	794
Income/(loss) from equity investments	(83)	64	(16)	(1)	(1)	-	(37)
Other income/(expense)	(15)	5	7	2	(2)	(23)	(26)
Earnings/(loss) before interest and income taxes	643	19	83	41	(7)	(48)	731
Interest expense							(369)
Income tax expense							(10)
Earnings							352
Capital expenditures1	1,070	81	144	10	-	10	1,315

Six months ended June 30, 2017	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**4,398**	**3,189**	**2,606**	**277**	**11,988**	**(196)**	**22,262**
Commodity and gas distribution costs	**(8)**	**(1,350)**	**(1,498)**	**3**	**(11,830)**	**200**	**(14,483)**
Operating and administrative	**(1,444)**	**(807)**	**(430)**	**(81)**	**(23)**	**(412)**	**(3,197)**
Depreciation and amortization	**(741)**	**(386)**	**(269)**	**(101)**	**(1)**	**(42)**	**(1,540)**
	2,205	**646**	**409**	**98**	**134**	**(450)**	**3,042**
Income/(loss) from equity investments	**194**	**265**	**13**	**2**	**2**	**(4)**	**472**
Other income/(expense)	**(3)**	**110**	**6**	**1**	**2**	**98**	**214**
Earnings/(loss) before interest and income taxes	**2,396**	**1,021**	**428**	**101**	**138**	**(356)**	**3,728**
Interest expense							**(1,051)**
Income tax expense							**(491)**
Earnings							**2,186**
Capital expenditures1	**1,194**	**2,029**	**492**	**229**	**1**	**68**	**4,013**

Six months ended June 30, 2016	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	4,356	1,267	1,779	256	9,244	(168)	16,734
Commodity and gas distribution costs	(5)	(946)	(1,059)	3	(9,213)	168	(11,052)
Operating and administrative	(1,446)	(246)	(278)	(77)	(34)	(19)	(2,100)
Depreciation and amortization	(682)	(149)	(164)	(95)	(1)	(23)	(1,114)
	2,223	(74)	278	87	(4)	(42)	2,468
Income/(loss) from equity investments	30	134	27	1	(3)	-	189
Other income/(expense)	2	20	17	2	(6)	215	250
Earnings/(loss) before interest and income taxes	2,255	80	322	90	(13)	173	2,907
Interest expense							(781)
Income tax expense							(427)
Earnings							1,699
Capital expenditures1	2,402	133	392	17	-	16	2,960

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

TOTAL ASSETS

	June 30, 20171	December 31, 2016
(unaudited; millions of Canadian dollars)		
Liquids Pipelines	**56,760**	52,043
Gas Pipelines and Processing	**47,256**	11,182
Gas Distribution	**19,063**	10,204
Green Power and Transmission	**6,035**	5,571
Energy Services	**1,667**	1,951
Eliminations and Other	**3,750**	4,881
	134,531	85,832

1 *Excludes goodwill allocation of $34.5 billion, in connection with the Merger Transaction (Note 5).*

4. EARNINGS PER COMMON SHARE

BASIC

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 - 13 million) for the three and six months ended June 30, 2017, resulting from the Company s reciprocal investment in Noverco Inc.

DILUTED

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.

Weighted average common shares outstanding used to calculate basic and diluted earnings per common share are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(number of common shares in millions)				
Weighted average common shares outstanding	**1,628**	917	**1,404**	897
Effect of dilutive options	**8**	8	**9**	7
Diluted weighted average common shares outstanding	**1,636**	925	**1,413**	904

For the three and six months ended June 30, 2017, 13,416,763 and 13,480,978 anti-dilutive stock options (2016 - 7,802,601 and 13,976,687) with a weighted average exercise price of $57.98 and $57.84 (2016 - $55.77 and $51.34) were excluded from the diluted earnings per common share calculation.

5. ACQUISITION AND DISPOSITIONS

ACQUISITION

Spectra Energy Corp

On February 27, 2017, Enbridge and Spectra Energy Corp (Spectra Energy) combined in a stock-for-stock merger transaction (the Merger Transaction) for a purchase price of $37.5 billion. Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge for each share of Spectra Energy common stock that they owned, giving Enbridge 100% ownership of Spectra Energy.

Consideration offered to complete the Merger Transaction included 691 million common shares of Enbridge at US$41.34 per share, based on the February 24, 2017 closing price on the New York Stock Exchange (NYSE), for a total value of $37,429 million in common shares issued to Spectra Energy shareholders, plus approximately $3 million in cash in lieu of any fractional shares, and 3.5 million share options with a fair value of $77 million, that were exchanged for Spectra Energy s outstanding stock compensation awards.

Spectra Energy, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America s leading natural gas infrastructure companies. Spectra Energy also owns and operates a crude oil pipeline system that connects Canadian and United States producers to refineries in the United States Rocky Mountain and Midwest regions. The combination brings together two highly complementary platforms to create North America s largest energy infrastructure company and meaningfully enhances customer optionality, positioning the Company for long-term growth opportunities, and strengthening the Company s balance sheet.

The Merger Transaction has been accounted for as a business combination under the acquisition method of accounting as prescribed by ASC 805 *Business Combinations*. The acquired tangible and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition.

The purchase price allocation was prepared on a preliminary basis and is subject to change as additional information becomes available concerning the fair value and tax bases of the assets acquired. The allocation of goodwill to reporting units is outstanding at the date of issuance of the Company s consolidated financial statements. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of Spectra Energy:

February 27,	2017
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	2,365
Property, plant and equipment, net (b)	34,680
Restricted long-term investments	144
Long-term investments (c)	5,000
Deferred amounts and other assets (d)	2,920
Intangible assets (e)	2,118
Current liabilities	(3,434)
Long-term debt (d)	(21,925)
Other long-term liabilities	(1,983)
Deferred income taxes	(8,331)
Noncontrolling interests (f)	(8,792)
	2,762
Goodwill (g)	34,747
	37,509
Purchase price:	
Common shares	37,429
Cash	3
Fair value of outstanding earned stock compensation awards recorded in Additional paid-in capital	77
	37,509

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 of $1,190 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 was determined using a market participant perspective, which is their carrying amount. The fair value of the remaining non-regulated property, plant and equipment was 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. (DCP Midstream), 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 PennEast Pipeline Company LLC (PennEast). The fair value of these investments was determined using an income approach.

d) Fair value of long-term debt was 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 interests includes approximately 78.4 million Spectra Energy Partners, LP (SEP) common units outstanding to the public, valued at the February 24, 2017 closing price of US$44.88 per common unit on the NYSE, 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 (Union Gas) and Westcoast Energy Inc.

g) The Company recorded $34.7 billion in goodwill, 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 $229 million. Costs incurred for the three and six months ended June 30, 2017 of $26 million and $178 million (six months ended December 31, 2016 - $51 million) are included in Operating and administrative expenses in the Consolidated Statements of Earnings.

For the six 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 $25 million, $49 million, $49 million, $44 million, $40 million respectively, and $196 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 June 30, 2017, Spectra Energy has generated approximately $2,398 million in revenues and $327 million in earnings.

The following supplemental pro forma consolidated financial information of the Company for the three and six months ended June 30, 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 June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars, except per share amounts)				
Revenues	**11,116**	9,387	**23,553**	20,049
Earnings attributable to Enbridge Inc. common shareholders[1]	**938**	511	**1,929**	2,067

1 Merger Transaction costs of $26 million and $178 million (after-tax $19 million and $130 million) were excluded from earnings for the three and six months ended June 30, 2017.

DISPOSITIONS

Sandpiper Project

During the three months ended June 30, 2017, the Company sold unused pipe related to the Sandpiper project for cash proceeds of approximately $130 million (US$97 million). A gain on disposal of $69 million (US$52 million) was included in Operating and administrative expense on the Consolidated Statements of Earnings. These assets were a part of the Company s Liquid Pipelines segment.

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 costs. A gain on disposal of $14 million (US$10 million) was included in Operating and administrative expense on the Consolidated Statements of Earnings. These assets were a part of the Company s Liquids Pipelines segment.

6. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Enbridge Holdings (DakTex) L.L.C.

Enbridge Holdings (DakTex) L.L.C. (DakTex) is owned 75% by a wholly-owned subsidiary of the Company and 25% by Enbridge Energy Partners, L.P. (EEP), through which the Company has an effective 27.6% interest in the equity investment, Bakken Pipeline System *(Note 7)*. EEP is the primary beneficiary because it has the power to direct DakTex s activities that most significantly impact its economic performance. The Company consolidates EEP and by extension also consolidates DakTex.

In connection with the acquisition of Spectra Energy *(Note 5)*, the Company has acquired both consolidated and unconsolidated variable interest entities (VIEs).

ACQUIRED CONSOLIDATED VARIABLE INTEREST ENTITIES

Spectra Energy Partners, LP

The Company acquired a 75% ownership in 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 most significantly impact its economic performance.

Valley Crossing Pipeline, LLC

Valley Crossing Pipeline, LLC (Valley Crossing), a wholly-owned subsidiary of the Company, is constructing a natural gas pipeline to transport natural gas within Texas. Valley Crossing is considered a VIE due to insufficient equity at risk to finance its activities. The Company is the primary beneficiary because it has the power to direct Valley Crossing s activities 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 consolidated VIEs and liabilities of Enbridge s consolidated VIEs for which creditors do not have recourse to the Company s general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

June 30,	**2017**
(millions of Canadian dollars)	
Assets	
Cash and cash equivalents	**448**
Accounts receivable and other	**1,217**
Inventory	**190**
	1,855
Property, plant and equipment, net	**30,794**
Long-term investments	**3,629**
Restricted long-term investments	**76**
Deferred amounts and other assets	**1,219**
Intangible assets, net	**104**
	37,677
Liabilities	
Short-term borrowings	**300**
Accounts payable and other	**1,707**
Interest payable	**140**
Current portion of long-term debt	**897**
	3,044
Long-term debt	**12,930**
Other long-term liabilities	**1,405**
Deferred income taxes	**692**
	18,071
Net assets before noncontrolling interests	**19,606**

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 because the power to direct Nexus activities that most significantly impact its economic performance is shared.

PennEast Pipeline Company, LLC

SEP owned a 10% equity investment in PennEast, which was increased to 20% in June 2017. 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 PennEast s activities that most significantly impact its economic performance.

The carrying amount of the Company s interest and its maximum exposure to loss in material unconsolidated VIEs are presented below:

June 30, 2017	Carrying Amount of Investment in VIE	Enbridge s Maximum Exposure to Loss
(millions of Canadian dollars)		
Nexus Gas Transmission, LLC	**662**	**1,342**
PennEast Pipeline Company, LLC	**56**	**355**
	718	**1,697**

7. LONG-TERM INVESTMENTS

BAKKEN PIPELINE SYSTEM

On February 15, 2017, EEP acquired an effective 27.6% interest in the Dakota Access and Energy Transfer Crude Oil Pipelines (collectively, the Bakken Pipeline System) for a purchase price of $2.0 billion (US$1.5 billion). The Bakken Pipeline System was placed into service on June 1, 2017. It connects the Bakken formation in North Dakota to markets in the eastern Petroleum Administration for Defense Districts and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost. For details regarding the Company s funding arrangement, refer to Note 10.

The Company accounts for its interest in the Bakken Pipeline System under the equity method of accounting. For the three and six months ended June 30, 2017, the Company recognized $8 million in equity earnings for this investment, net of amortization of the purchase price basis difference.

The Company s equity investment includes the unamortized excess of the purchase price over the underlying net book value, or basis difference, of the investees assets at the purchase date, which is comprised of $19 million in goodwill and $1,210 million in amortizable assets included within the Liquids Pipelines segment. The Company amortized $4 million for the three and six months ended June 30, 2017, which was recorded as a reduction to equity earnings.

HOHE SEE OFFSHORE WIND PROJECT

On 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 is expected to be fully operational in late 2019. The carrying amount of the investment is $462 million (312 million), which is included within the Green Power and Transmission segment, and represents Enbridge s portion of the costs incurred to date.

8. DEBT

CREDIT FACILITIES

		June 30, 2017		
	Maturity Dates	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2018-2022	**6,826**	**5,686**	**1,140**
Enbridge (U.S.) Inc.	2018-2019	**3,805**	**2,216**	**1,589**
Enbridge Energy Partners, L.P.	2019-2020	**3,409**	**1,994**	**1,415**
Enbridge Gas Distribution Inc.	2018	**1,017**	**684**	**333**
Enbridge Income Fund	2019	**1,500**	**771**	**729**
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**26**	**-**	**26**
Enbridge Pipelines Inc.	2018	**3,000**	**1,105**	**1,895**
Enbridge Southern Lights LP	2018	**5**	**-**	**5**
Spectra Energy Capital, LLC[2]	2021	**1,299**	**-**	**1,299**
Spectra Energy Partners[2]	2021	**3,247**	**1,721**	**1,526**
Westcoast Energy Inc.[2]	2021	**400**	**-**	**400**
Union Gas Limited[2]	2021	**700**	**300**	**400**
Total committed credit facilities		**25,234**	**14,477**	**10,757**

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 5).*

During the second quarter of 2017, the Company completed the following term debt offerings:

- $1.2 billion of unsecured medium-term notes with maturity dates ranging from 2022 to 2044 and fixed interest rates ranging from 3.2% to 4.6%.

- $750 million of unsecured floating rate notes which mature in 2019 and carry an interest rate equal to the three-month banker s acceptance rate plus 59 basis points.

- US$500 million of unsecured floating rate notes which mature in 2020 and carry an interest rate equal to the three-month London Interbank Offered Rate (LIBOR) rate plus 70 basis points.

During the second quarter of 2017, SEP issued US$400 million of unsecured floating rate notes which mature in 2020 and carry an interest rate equal to the three-month LIBOR rate plus 70 basis points.

During the first quarter of 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 $556 million (December 31, 2016 - $335 million) of uncommitted demand credit facilities, of which $148 million (December 31, 2016 - $177 million) were unutilized as at June 30, 2017.

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 2018 to 2022.

As at June 30, 2017, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $13,377 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.

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ANNUAL MATURITIES AND INTEREST OBLIGATIONS[1]

(millions of Canadian dollars)	2017[2]	2018	2019	2020	2021	Thereafter
Annual maturities[3]	**1,138**	**3,227**	**4,790**	**5,191**	**2,787**	**34,510**
Interest obligations[4]	**1,238**	**2,336**	**2,127**	**1,905**	**1,726**	**19,412**

1 *This table excludes the debt issuances and tender offers that occurred subsequent to June 30, 2017* (Note 16).

2 *For the six months ending December 31, 2017.*

3 *Includes the Company s debenture, term note and non-revolving credit facility maturities.*

4 *Includes the Company s debentures and term notes bearing interest at fixed and floating rates.*

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 and have been reflected in the table above.

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.

DEBT COVENANTS

The Company was in compliance with all terms and conditions of its committed credit facility agreements and term debt indentures as at June 30, 2017.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income (AOCI) attributable to Enbridge Inc. common shareholders for the six months ended June 30, 2017 and 2016 are as follows:

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
Balance at January 1, 2017	**(746)**	**(629)**	**2,700**	**37**	**(304)**	**1,058**
Other comprehensive income/(loss) retained in AOCI	**(44)**	**222**	**(899)**	**3**	**-**	**(718)**
Other comprehensive (income)/loss reclassified to earnings						

Interest rate contracts1	**71**	**-**	**-**	**-**	**-**	**71**
Commodity contracts2	**(4)**	**-**	**-**	**-**	**-**	**(4)**
Foreign exchange contracts3	**2**	**-**	**-**	**-**	**-**	**2**
Amortization of pension and OPEB actuarial loss and prior service cost5	**-**	**-**	**-**	**-**	**10**	**10**
	25	**222**	**(899)**	**3**	**10**	**(639)**
Tax impact						
Income tax on amounts retained in AOCI	**12**	**(2)**	**-**	**5**	**-**	**15**
Income tax on amounts reclassified to earnings	**(23)**	**-**	**-**	**-**	**(3)**	**(26)**
	(11)	**(2)**	**-**	**5**	**(3)**	**(11)**
Balance at June 30, 2017	**(732)**	**(409)**	**1,801**	**45**	**(297)**	**408**

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	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB 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	(711)	384	(1,253)	(7)	-	(1,587)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	52	-	-	-	-	52
Commodity contracts2	(5)	-	-	-	-	(5)
Foreign exchange contracts3	1	-	-	-	-	1
Other contracts4	(31)	-	-	-	-	(31)
Amortization of pension and OPEB actuarial loss and prior service cost5	-	-	-	-	13	13
	(694)	384	(1,253)	(7)	13	(1,557)
Tax impact						
Income tax on amounts retained in AOCI	200	(13)	-	6	-	193
Income tax on amounts reclassified to earnings	(10)	-	-	-	(4)	(14)
	190	(13)	-	6	(4)	179
Balance at June 30, 2016	(1,192)	(424)	2,112	36	(278)	254

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 benefit costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

10. NONCONTROLLING INTERESTS

UNITED STATES SPONSORED VEHICLE STRATEGY

On April 28, 2017, Enbridge completed 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. As a result of these actions, the Company recorded an increase in Noncontrolling interests of $496 million, inclusive of foreign currency translation adjustments, and a decrease in Additional paid-in capital of $442 million, net of deferred income taxes of $267 million.

Acquisition of Midcoast Assets and Privatization of Midcoast Energy Partners, L.P.

On April 27, 2017, Enbridge completed its previously-announced merger through a wholly-owned subsidiary, through which it privatized Midcoast Energy Partners, L.P. (MEP) by acquiring all of the outstanding publicly-held common units of MEP for total consideration of approximately US$170 million.

On June 28, 2017, Enbridge, through a wholly-owned subsidiary, acquired all of EEP s interest in the Midcoast gas gathering and processing business for cash consideration of US$1.3 billion plus existing indebtedness of MEP of US$953 million.

As a result of the above transactions, 100% of the Midcoast gas gathering and processing business is now owned by Enbridge.

EEP Strategic Restructuring Actions

On April 27, 2017, 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 Class F units are entitled to (i) 13% of all distributions in excess of US$0.295 per EEP unit, but equal to or less than US$0.35 per EEP unit, and (ii) 23% of all distributions in excess of US$0.35 per EEP unit. 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. Further, in conjunction with the restructuring actions, EEP terminated a receivable purchase agreement with an Enbridge wholly-owned special purpose entity.

Finalization of Bakken Pipeline System Joint Funding Agreement

On April 27, 2017, Enbridge entered into a joint funding arrangement with EEP whereby Enbridge owns 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System. Under this arrangement, EEP has retained a five-year option to acquire an additional 20% interest. On finalization of this joint funding arrangement, EEP repaid the outstanding balance on its US$1.5 billion credit agreement with Enbridge, which it had drawn upon to fund the initial purchase.

REDEEMABLE NONCONTROLLING INTERESTS

Enbridge Income Fund Holdings Inc. Secondary Offering

On April 18, 2017, the Company and Enbridge Income Fund Holdings Inc. (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 Enbridge Income 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%. As a result of the Secondary Offering, the Company recorded a decrease in Redeemable noncontrolling interests of $87 million and an increase in Additional paid-in capital of $87 million.

11. 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 term 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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.5%.

As a result of the Merger Transaction, the Company is exposed to changes in the fair value of the fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used to hedge against the future changes to the fair value of the fixed rate debt. The Company has implemented a program to significantly mitigate the impact of fluctuations in the fair value of the fixed rate debt via execution of 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 3.8%.

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

Commodity Price Risk

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

June 30, 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	**5**	**3**	**-**	**61**	**69**	**(59)**	**10**
Interest rate contracts	**1**	**-**	**4**	**-**	**5**	**(1)**	**4**
Commodity contracts	**7**	**-**	**-**	**185**	**192**	**(50)**	**142**
	13	**3**	**4**	**246**	**266**	**(110)**	**156**
Deferred amounts and other assets							
Foreign exchange contracts	**2**	**2**	**-**	**116**	**120**	**(111)**	**9**
Interest rate contracts	**2**	**-**	**19**	**-**	**21**	**(1)**	**20**
Commodity contracts	**17**	**-**	**-**	**23**	**40**	**(24)**	**16**
	21	**2**	**19**	**139**	**181**	**(136)**	**45**
Accounts payable and other							
Foreign exchange contracts	**(5)**	**(228)**	**-**	**(551)**	**(784)**	**59**	**(725)**
Interest rate contracts	**(315)**	**-**	**-**	**(133)**	**(448)**	**1**	**(447)**
Commodity contracts	**-**	**-**	**-**	**(139)**	**(139)**	**50**	**(89)**
Other contracts	**(1)**	**-**	**-**	**(6)**	**(7)**	**-**	**(7)**
	(321)	**(228)**	**-**	**(829)**	**(1,378)**	**110**	**(1,268)**
Other long-term liabilities							
Foreign exchange contracts	**-**	**(34)**	**-**	**(1,533)**	**(1,567)**	**111**	**(1,456)**
Interest rate contracts	**(266)**	**-**	**(9)**	**(193)**	**(468)**	**1**	**(467)**
Commodity contracts	**-**	**-**	**-**	**(164)**	**(164)**	**24**	**(140)**
Other contracts	**(1)**	**-**	**-**	**(1)**	**(2)**	**-**	**(2)**
	(267)	**(34)**	**(9)**	**(1,891)**	**(2,201)**	**136**	**(2,065)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**2**	**(257)**	**-**	**(1,907)**	**(2,162)**	**-**	**(2,162)**
Interest rate contracts	**(578)**	**-**	**14**	**(326)**	**(890)**	**-**	**(890)**
Commodity contracts	**24**	**-**	**-**	**(95)**	**(71)**	**-**	**(71)**
Other contracts	**(2)**	**-**	**-**	**(7)**	**(9)**	**-**	**(9)**
	(554)	**(257)**	**14**	**(2,335)**	**(3,132)**	**-**	**(3,132)**

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.

June 30, 2017	2017	2018	2019	2020	2021	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**834**	**2**	**2**	**2**	**-**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**3,816**	**3,041**	**3,246**	**3,258**	**567**	**223**
Foreign exchange contracts - British pound (GBP) forwards - purchase *(millions of GBP)*	**62**	**9**	**-**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**89**	**25**	**27**	**177**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**123**	**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)*	**2,958**	**5,051**	**1,629**	**220**	**98**	**296**
Interest rate contracts - long-term receive fixed rate *(millions of Canadian dollars)*	**891**	**1,302**	**900**	**671**	**345**	**320**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**2,439**	**2,714**	**762**	**-**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**48**	**40**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(81)**	**(62)**	**(10)**	**-**	**(1)**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(2)**	**(10)**	**-**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(5)**	**(10)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt per hour (MW/H))*	**43**	**30**	**31**	**35**	**(3)**	**(43)**

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 *(MW/H)*	40	30	31	35	(3)	(43)

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

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

	Three months ended		Six months ended	
	June 30,		June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**3**	2	**1**	(33)
Interest rate contracts	**(41)**	(428)	**(55)**	(1,004)
Commodity contracts	**(9)**	(18)	**12**	(2)
Other contracts	**(6)**	6	**(15)**	37
Net investment hedges				
Foreign exchange contracts	**65**	(12)	**73**	72
	12	(450)	**16**	(930)
Amount of (gain)/loss reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(102)**	(1)	**(101)**	2
Interest rate contracts[2]	**36**	72	**84**	51
Commodity contracts[3]	**(2)**	2	**(4)**	(6)
Other contracts[4]	**4**	(4)	**13**	(30)
	(64)	69	**(8)**	17
Amount of (gain)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**4**	5	**6**	31
	4	5	**6**	31

1 *Reported within Transportation and other services revenues and Other income/(expense) 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 loss of $62 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 30 months as at June 30, 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 and six months ended June 30, 2017, the Company recognized an unrealized gain of $3 million and $1 million (2016 - nil) on the derivative and an unrealized loss of $3 million and $1 million (2016 - nil) on the hedged item in earnings. 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 June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Foreign exchange contracts1	**434**	28	**707**	1,044
Interest rate contracts2	**32**	4	**14**	8
Commodity contracts3	**19**	(114)	**182**	(298)
Other contracts4	**(5)**	5	**(5)**	11
Total unrealized derivative fair value gain/(loss), net	**480**	(77)	**898**	765

1 *For the respective six months ended periods, reported within Transportation and other services revenues (2017 - $398 million gain; 2016 - $564 million gain) and Other income/(expense) (2017 - $309 million gain; 2016 - $480 million gain) in the Consolidated Statements of Earnings.*
2 *Reported as a decrease within Interest expense in the Consolidated Statements of Earnings.*
3 *For the respective six months ended periods, reported within Transportation and other services revenues (2017 - $37 million loss; 2016 - $2 million gain), Commodity sales (2017 - $197 million gain; 2016 - $302 million loss), Commodity costs (2017 - $9 million gain; 2016 - $6 million gain) and Operating and administrative expense (2017 - $13 million gain; 2016 - $4 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 June 30, 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:

	June 30, 2017	December 31, 2016
(millions of Canadian dollars)		
Canadian financial institutions	**56**	39
United States financial institutions	**82**	179
European financial institutions	**133**	106
Asian financial institutions	**4**	1
Other[1]	**126**	162
	401	487

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

As at June 30, 2017, the Company had provided letters of credit totalling $198 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 June 30, 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 Enbridge Gas Distribution Inc. 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:

June 30, 2017	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**69**	**-**	**69**
Interest rate contracts	**-**	**5**	**-**	**5**
Commodity contracts	**7**	**68**	**117**	**192**
	7	**142**	**117**	**266**
Long-term derivative assets				
Foreign exchange contracts	**-**	**120**	**-**	**120**
Interest rate contracts	**-**	**21**	**-**	**21**
Commodity contracts	**-**	**5**	**35**	**40**
	-	**146**	**35**	**181**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(784)**	**-**	**(784)**
Interest rate contracts	**-**	**(448)**	**-**	**(448)**
Commodity contracts	**(4)**	**(37)**	**(98)**	**(139)**
Other contracts	**-**	**(7)**	**-**	**(7)**
	(4)	**(1,276)**	**(98)**	**(1,378)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(1,567)**	**-**	**(1,567)**
Interest rate contracts	**-**	**(468)**	**-**	**(468)**
Commodity contracts	**-**	**(6)**	**(158)**	**(164)**
Other	**-**	**(2)**	**-**	**(2)**
	-	**(2,043)**	**(158)**	**(2,201)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,162)**	**-**	**(2,162)**
Interest rate contracts	**-**	**(890)**	**-**	**(890)**
Commodity contracts	**3**	**30**	**(104)**	**(71)**
Other contracts	**-**	**(9)**	**-**	**(9)**
	3	**(3,031)**	**(104)**	**(3,132)**

December 31, 2016 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
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:

June 30, 2017 *(fair value in millions of Canadian dollars)*	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price	Unit of Measurement
Commodity contracts - financial1						
Natural gas	11	Forward gas price	3.09	4.53	3.84	$/mmbtu3
Crude	1	Forward crude price	40.91	47.61	44.83	$/barrel
NGL	-	Forward NGL price	0.33	1.38	1.04	$/gallon
Power	(135)	Forward power price	27.95	67.03	47.15	$/MW/H
Commodity contracts - physical1						
Natural gas	(30)	Forward gas price	2.30	8.95	3.47	$/mmbtu3
Crude	39	Forward crude price	39.51	72.27	56.50	$/barrel
NGL	6	Forward NGL price	0.32	1.96	0.98	$/gallon
Commodity options2						
Crude	3	Option volatility	23%	31%	26%	
NGL	-	Option volatility	32%	87%	56%	
Power	1	Option volatility	26%	45%	33%	
	(104)					

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:

	Six months ended June 30,	
	2017	2016
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**(295)**	54
Total gain/(loss)		
Included in earnings[1]	**101**	(96)
Included in OCI	**8**	(8)
Settlements	**82**	(126)
Level 3 net derivative liability at end of period	**(104)**	(176)

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 June 30, 2017 or 2016.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Equity investments in other entities with no actively quoted prices available for fair value measurement are recorded at cost by the Company. The carrying value of all equity investments recognized at cost totalled $109 million as at June 30, 2017 (December 31, 2016 - $110 million).

The Company has Restricted long-term investments held in trust totalling $237 million as at June 30, 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 $364 million as at June 30, 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 June 30, 2017, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2016 - $580 million).

As at June 30, 2017, the Company s long-term debt had a carrying value of $64.9 billion (December 31, 2016 - $40.8 billion) before debt issuance cost and a fair value of $68.7 billion (December 31, 2016 - $43.9 billion). The Company also has noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets. As at June 30, 2017, the noncurrent notes receivable has a carrying value of $92 million (December 31, 2016 - nil) and a fair value of $92 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 six months ended June 30, 2017, the Company recognized an unrealized foreign exchange gain on the translation of United States dollar denominated debt of $275 million (2016 - $277 million) and an unrealized gain on the change in fair value of its outstanding foreign exchange forward contracts of $75 million (2016 - $73 million) in OCI. The Company recognized a realized loss of $38 million (2016 - $1 million) in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized loss of $90 million (2016 - $33 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 six months ended June 30, 2017 (2016 - nil).

12. INCOME TAXES

The effective income tax rates for the three and six months ended June 30, 2017 were 19.1% and 18.3%, respectively (2016 - 2.8% and 20.1%). The period-over-period change in the effective income tax rates in 2017 is primarily attributable to the rate-regulated tax benefit and other permanent items relative to the increase in earnings for the three and six months ended June 30, 2017.

13. PENSION AND OTHER POSTRETIREMENT BENEFITS

NET PERIODIC BENEFIT COSTS RECOGNIZED

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
(millions of Canadian dollars)				
Service cost	**62**	41	**116**	83
Interest cost	**47**	23	**79**	49
Expected return on plan assets	**(73)**	(38)	**(124)**	(76)
Amortization of actuarial loss	**8**	9	**17**	18
Net periodic benefit costs	**44**	35	**88**	74

ACQUIRED PENSION PLANS

In connection with the Merger Transaction *(Note 5),* 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 acquired Canadian defined benefit plans provide retirement benefits based on each plan participant s years of service and final average earnings. Under the acquired Canadian defined contribution plan, Company contributions are determined according to the terms of the plan and are based on each plan participant s age, years of service and current eligible earnings. In connection with the Merger Transaction, the Company also assumed non-qualified defined benefit supplemental pensions provided to all employees who retire under a Canadian 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 provide Company-funded defined benefit plans 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 assumed non-qualified, non-contributory and unfunded defined benefit plans, and other non-qualified plans such as savings and deferred compensation plans, covering certain current and former executives based in the United States. These non-qualified pension plans have no plan assets.

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

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.

The following is a summary of the fair value of the Canadian and United States Plan and OPEB-related balances assumed at February 27, 2017:

	Pension		OPEB	
February 27, 2017	U.S.	Canada	U.S.	Canada
(millions of Canadian dollars)				
Projected benefit obligation	818	1,505	275	146
Fair value of plan assets	737	1,290	103	-
Underfunded status	(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 assumed pension plans and OPEB are as follows:

	Pension		OPEB	
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 OPEB 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 Plans	7.5%	4.5%	2037

Acquired Plan Assets

Canadian and United States 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 Plan 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 Plans. Equity securities 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 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 assumed Canadian and United States Plan 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 fixed income securities based on long-term expectations.

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Expected Rate of Return on Acquired Plan Assets

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

Target Mix for Acquired 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 Acquired Plan Assets

Acquired 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 acquired pension assets were invested 48.9% in equity securities, 46.7% in fixed income securities, and 4.4% in cash and cash equivalents and other. The OPEB assets were invested 38.8% in equity securities, 47.6% in fixed income securities, and 13.6% in cash and cash equivalents and other.

The following table summarizes the Company s acquired pension and OPEB financial instruments at fair value:

February 27, 2017 *(millions of Canadian dollars)*	Level 1[1]	Level 2[1]	Level 3[1]	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 *See Note 11 for details on the nature of level 1, level 2 and level 3 fair value measurements.*

Acquired Plan Contributions by the Company

Year ended December 31,	Pension	OPEB

(millions of Canadian dollars)		
Contributions expected to be paid in 2017	25	8

Benefits Expected to be Paid by the Company Related to the Acquired Plans

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

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 material related party transactions and their impact on earnings for the three and six months ended June 30, 2017.

DCP Midstream, a joint venture, processes certain of the Company s pipeline customers natural gas to meet natural gas quality specifications in order for the natural gas to be transported on the Company s Texas Eastern Transmission, LP system. DCP Midstream processes the natural gas and sells the NGLs that are extracted from the natural 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 $12 million (US$9 million) and $19 million (US$14 million) classified as revenue from Transportation and other services in the Company s Consolidated Statements of Earnings for the three and six months ended June 30, 2017, respectively.

The Company provides certain administrative and other services to certain operating entities and recorded recoveries of costs from these affiliates of $34 million (US$26 million) and $53 million (US$40 million) for the three and six months ended June 30, 2017, respectively. Cost recoveries are classified as a reduction to Operating and administrative expense in the Consolidated Statements of Earnings. Outstanding receivables from these affiliates totalled $29 million (US$22 million) as at June 30, 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 was reported near Marshall, Michigan.

As at June 30, 2017, EEP s cumulative 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 June 30, 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.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. As at June 30, 2017, 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. One action or claim is 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 this case, the Company does not expect the outcome of this action to be material to its results of operations or financial condition.

Line 6B Fines and Penalties

As at June 30, 2017, EEP s total estimated costs related to the Line 6B crude oil release include US$69 million in fines and penalties, which includes fines and penalties from the Department of Justice as discussed below.

Consent Decree

On May 23, 2017, the United States District Court for the Western District of Michigan, Southern Division, approved the Consent Decree. The Consent Decree is EEP s signed settlement agreement with the United States Environmental Protection Agency and the United States Department of Justice regarding Lines 6A and 6B crude oil releases. On June 15, 2017, Enbridge made a total payment of US$68 million as required by the Consent Decree, which reflects US$61 million for the civil penalty for the Line 6B release, US$1 million for the Line 6A release, and US$6 million for past removal costs and interest.

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 interim consolidated financial position or results of operations.

16. SUBSEQUENT EVENTS

DECONSOLIDATION OF SABAL TRAIL TRANSMISSION, LLC

On July 3, 2017, Sabal Trail Transmission, LLC (Sabal Trail) was placed into service. As a result, the Company is no longer the primary beneficiary as the power to direct the activities of Sabal Trail is now shared, and Sabal Trail will be deconsolidated and accounted for under the equity method of accounting. As at June 30, 2017, the total Sabal Trail assets and liabilities included in the Consolidated Statements of Financial Position were $4.0 billion (US$3.1 billion) and $182 million (US$140 million), respectively.

DEBT ISSUANCES

On July 7, 2017, Enbridge completed an offering of aggregated US$1.4 billion of senior unsecured notes (the Notes). The Notes consisted of two US$700 million tranches with fixed interest rates of 2.9% and 3.7%, and mature in five and 10 years, respectively. Approximately US$1.2 billion of the net proceeds from the Notes were used to pay for the redemption of the tendered notes described below.

On July 14, 2017, Enbridge also completed an offering of US$1.0 billion of fixed-to-floating rate subordinated notes. These notes carry a fixed interest rate of 5.5% for the initial 10 years with a floating rate thereafter. These notes have a maturity of 60 years and are callable after 10 years.

SPECTRA ENERGY CAPITAL, LLC TENDER OFFERS

On July 7, 2017, Enbridge and Spectra Energy Capital, LLC (Spectra Capital) completed a cash tender offer to purchase the principal amount of Spectra Capital s outstanding 8.0% senior unsecured notes due 2019. The principal amount tendered and accepted was US$267 million. Spectra Capital paid the consenting note holders an aggregate cash consideration of US$310 million.

On July 13, 2017, pursuant to a cash tender offer, Spectra Capital purchased the principal amount of its outstanding senior unsecured notes carrying interest rates ranging from 3.3% to 7.5%, with maturities ranging from one to 21 years. The principal amount tendered and accepted was US$761 million. Spectra Capital paid the consenting note holders an aggregate cash consideration of US$857 million.

OLYMPIC PIPELINE DISPOSITION

On July 31, 2017, the Company completed the sale of its interest in Olympic Pipeline for cash proceeds of approximately $213 million (US$160 million). This interest was a part of the Company s Liquid Pipelines segment.