ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 31, 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, L.L.C.
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
Federal Court	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, L.P.
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 MONTHS ENDED MARCH 31, 2017

This Management's Discussion and Analysis (MD&A) dated May 11, 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 months ended March 31, 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 annual 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 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 of approximately $48 billion 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 will continue to be carried out through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services. As a result of the Merger Transaction, effective February 27, 2017:

- Liquids Pipelines also includes results from the operation of the Express-Platte System, a crude oil pipeline system in Canada and the United States comprising the Express pipeline and the Platte pipeline systems.
- Gas Pipelines and Processing also includes Spectra's United States Transmission, BC Pipeline & Field Services, Canadian Midstream and Maritimes & Northeast Canada businesses, certain other gas pipeline, gathering and storage assets, as well as the results of the Company's 50% interest in DCP Midstream.

- Gas Distribution also includes results from the operation of Union Gas Limited (Union Gas), a major Canadian natural gas storage, transmission and distribution company that serves customers in Ontario.

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, L.P. (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 annual MD&A, were taken to restore EEP's value proposition to its unitholders and to Enbridge:

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

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

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

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 adjusted earnings from EEP. These lower contributions will be partially offset by an increased contribution of adjusted earnings through Enbridge's increased ownership in the Class A common units.

PRIVATIZATION OF MIDCOAST ENERGY PARTNERS

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

ASSET MONETIZATION

In conjunction with the announcement of the Merger Transaction in September 2016, the Company also 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.

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 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 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%.

With the completion of the Secondary Offering, the Ozark pipeline system sale and other divestitures completed in 2016, the Company has exceeded the $2 billion monetization target it announced in September 2016.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**1,124**	1,612
Gas Pipelines and Processing	**339**	61
Gas Distribution	**275**	239
Green Power and Transmission	**50**	49
Energy Services	**156**	(6)
Eliminations and Other	**(315)**	221
Earnings before interest and income taxes	**1,629**	2,176
Interest expense	**(486)**	(412)
Income taxes	**(198)**	(417)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(224)**	(61)
Preference share dividends	**(83)**	(73)
Earnings attributable to common shareholders	**638**	1,213
Earnings per common share	**0.54**	1.38
Diluted earnings per common share	**0.54**	1.38

EARNINGS BEFORE INTEREST AND INCOME TAXES

For the three months ended March 31, 2017, earnings before interest and income taxes (EBIT) was $1,629 million compared with $2,176 million for the three months ended March 31, 2016. As discussed below in *Adjusted EBIT*, the first quarter of 2017 earnings were positively impacted by the contributions from new assets following the completion of the Merger Transaction on February 27, 2017 – refer to *Merger with Spectra Energy.*

The quarter-over-quarter decrease in EBIT was largely driven by the Liquids Pipelines segment, which delivered lower adjusted EBIT for the three months ended March 31, 2017, mainly attributable to a lower effective foreign exchange rate, the divestiture of certain Liquids Pipelines assets and a change in normalization policy for recording make-up rights. EBIT for the rest of the year is expected to be positively impacted by increased throughput optimization on the mainline system and the effect of new projects coming into service in 2017.

The comparability of the Company's earnings quarter-over-quarter is also impacted by a number of unusual, non-recurring or non-operating factors that are enumerated in the Non-GAAP Reconciliation tables and discussed in the results for each reporting segment, the most significant of which are changes in unrealized derivative fair value gains and losses. For the three months ended March 31, 2017, the Company's EBIT reflected $416 million of unrealized derivative fair value gains compared with gains of $932 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 create 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.

EBIT for the first quarter of 2017 also reflected charges of $152 million ($111 million after-tax) with respect to costs incurred in conjunction with 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.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $638 million for the three months ended March 31, 2017, or earnings of $0.54 per common share, compared with $1,213 million, or earnings of $1.38 per common share, for the three months ended March 31, 2016. As further discussed in *Adjusted EBIT*, first quarter earnings were positively impacted by contributions from assets acquired following the completion of the Merger Transaction on February 27, 2017 – refer to *Merger with Spectra Energy.*

In addition to the factors discussed in *EBIT* above and in *Adjusted EBIT* and *Adjusted Earnings* below, the quarter-over-quarter comparability of earnings attributable to common shareholders was impacted by a number of unusual, non-recurring and non-operating factors that are summarized and described under *Non-GAAP Reconciliation – EBIT to Adjusted Earnings.*

A lower earnings per common share for the three months ended March 31, 2017 compared with the corresponding 2016 period also reflected the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction, and other issuances of approximately 75 million common shares in 2016, inclusive of 56 million common shares issued in March 2016.

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; 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 cost and impact to the Company's overall financial performance of complying with the settlement consent decree related to Line 6B and Line 6A; estimated future dividends; recovery of the costs of the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) through the use of surcharges; 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; expectations on impact of hedging program; strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy and the regulatory framework and recovery of deferred costs by Enbridge Gas New Brunswick Inc.

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; cost of complying with the settlement consent decree related to Line 6B and Line 6A; 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. These factors are relevant to 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, exchange rates, interest rates, commodity prices, political decisions, supply of and demand for commodities and the settlement consent decree related to Line 6B and Line 6A, 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 or loss 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 summarize the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATION – EBIT TO ADJUSTED EARNINGS

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Earnings before interest and income taxes	**1,629**	2,176
Adjusting items[1]:		
Change in unrealized derivative fair value gains[2]	**(416)**	(932)
Unrealized intercompany foreign exchange loss	**7**	60
Hydrostatic testing	**-**	(12)
Make-up rights adjustments[3]	**-**	67
Leak remediation costs, net of leak insurance recoveries	**4**	15
Warmer than normal weather[4]	**-**	17
Project development and transaction costs	**153**	-
Employee severance and restructuring costs	**129**	-
Other	**9**	(17)
Adjusted earnings before interest and income taxes	**1,515**	1,374
Interest expense	**(486)**	(412)
Income taxes	**(198)**	(417)
Earnings attributable to noncontrolling interest and redeemable noncontrolling interests	**(224)**	(61)
Preference share dividends	**(83)**	(73)
Adjusting items in respect of:		
Interest expense	**21**	18
Income taxes	**54**	241
Noncontrolling interests and redeemable noncontrolling interests	**76**	(7)
Adjusted earnings	**675**	663

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 March 31,	
	2017	2016
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**970**	1,084
Gas Pipelines and Processing	**336**	87
Gas Distribution	**269**	240
Green Power and Transmission	**50**	48
Energy Services	**(5)**	1
Eliminations and Other	**(105)**	(86)
Adjusted earnings before interest and income taxes	**1,515**	1,374
Interest expense[1]	**(465)**	(394)
Income taxes[1]	**(144)**	(176)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(148)**	(68)
Preference share dividends	**(83)**	(73)
Adjusted earnings	**675**	663
Adjusted earnings per common share	**0.57**	0.76

1 These balances are presented net of adjusting items.

Adjusted EBIT

For the three months ended March 31, 2017, adjusted EBIT was $1,515 million, an increase of $141 million over the comparable period in 2016. The first quarter of 2017 adjusted EBIT reflected 33 days of results of operations from new assets following the completion of the Merger Transaction on February 27, 2017 - refer to *Merger with Spectra Energy.* Contributions from these new assets were the key driver for the quarter-over-quarter growth in consolidated adjusted EBIT.

Growth in consolidated 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. Quarter-over-quarter growth for this segment also reflected contributions from the Tupper Main and Tupper West gas plants (the Tupper Plants) acquired in April 2016, as well as higher adjusted EBIT from Alliance Pipeline that was driven by strong demand for seasonal firm service in the first quarter of 2017.

Adjusted EBIT for Liquids Pipelines in the first quarter of 2017 was lower than the comparable period in 2016, attributable to several factors, including a lower quarter-over-quarter foreign exchange hedge rate used to record Canadian Mainline revenues. The IJT Benchmark Toll and its components are set in United States dollars and the majority of the Company's foreign exchange risk on Canadian Mainline revenues is hedged. The effective hedge rate for the translation of Canadian Mainline United States dollar transactional revenues for the first quarter of 2017 was $1.04 compared with $1.11 for the corresponding period in 2016. In addition, the Canadian dollar foreign exchange rate at which United States operations were translated strengthened from $1.37 in the first quarter of 2016 to $1.32 for the corresponding period in 2017.

Further contributing to lower quarter-over-quarter EBIT was the sale of certain assets and reduced surcharges on the Bakken System and lower contributions on rail facilities owned by EEP due to expiry of contracts. In addition, EBIT generated by the United States Mid-Continent and Gulf Coast Systems were lower in the first quarter of 2017 as, effective January 1, 2017, the Company no longer adjusts for revenue that is deferred from certain take or pay tolling arrangements with make-up rights in its determination of adjusted EBIT. EBIT for the rest of the year is expected to be positively impacted by increased throughput optimization on the mainline system and the effect of new projects coming into service in 2017.

Within the Gas Distribution segment, Enbridge Gas Distribution Inc. (EGD) generated lower adjusted EBIT in the first quarter of 2017 compared with the corresponding 2016 period, primarily due to lower distribution revenues attributable to warmer than normal weather in the first quarter of 2017. Effective

January 1, 2017, EGD ceased to exclude the effect of warmer/colder weathers from its adjusted EBIT. The effect of the warmer weather in EGD's adjusted EBIT for the first quarter of 2017 was approximately $29 million. The quarter-over-quarter decrease in EGD's adjusted EBIT was more than offset by contributions from Union Gas since the completion of the Merger Transaction.

Within Eliminations and Other, higher operating and administrative expenses drove an increase in the quarter-over-quarter adjusted loss. Operating and administrative costs were higher in the first quarter of 2017 due to higher information technology and other centralized service costs post integration with Spectra Energy and proportionally lower recoveries from business units during the quarter.

Adjusted Earnings

Adjusted earnings were $675 million, or $0.57 per common share, for the three months ended March 31, 2017 compared with $663 million, or $0.76 per common share, for the three months ended March 31, 2016.

Partially offsetting the quarter-over-quarter adjusted EBIT growth discussed above was higher interest expense as a result of debt assumed in the Merger Transaction. Preference share dividends were also higher quarter-over-quarter reflecting additional preference shares issued in the fourth quarter of 2016 to partially fund the Company's growth capital program.

Income taxes were lower in the first quarter of 2017 despite the quarter-over-quarter increase in adjusted earnings due to a valuation allowance expense recorded in the first quarter of 2016.

Adjusted earnings attributable to noncontrolling interests and redeemable noncontrolling interests increased in the first quarter of 2017 compared with the corresponding 2016 period. The increase was driven by additional noncontrolling interests in respect of the assets acquired in the Merger Transaction and an increase in earnings attributable to noncontrolling interests as a result of the EEP restructuring.

Interest expense, income taxes and noncontrolling interests and redeemable noncontrolling interests were also impacted by adjustments for unusual, non-recurring and non-operating factors.

Adjusted earnings per common share for the three months ended March 31, 2017 compared with the corresponding 2016 period also reflected the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction, and other issuances of approximately 75 million common shares in 2016, inclusive of 56 million common shares issued in March 2016.

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 March 31, 2017.

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Norlite Pipeline System (the Fund Group)[3]	$1.3 billion	$1.0 billion	2017	Complete
2. Bakken Pipeline System (EEP)	US$1.5 billion	US$1.5 billion	2017	Substantially complete
3. Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$2.2 billion	2017 (in phases)	Under construction
4. Lakehead System Mainline Expansion - Line 61 (EEP)[4]	US$0.4 billion	US$0.4 billion	2019	Under construction
5. Canadian Line 3 Replacement Program (the Fund Group)[5]	$4.9 billion	$1.6 billion	2019	Pre-construction
6. U.S. Line 3 Replacement Program (EEP)[4,5]	US$2.6 billion	US$0.5 billion	2019	Pre-construction
7. Other - Canada	$0.3 billion	$0.1 billion	2017-2018	Various
GAS PIPELINES AND PROCESSING				
8. Sabal Trail (SEP)[6]	US$1.6 billion	US$1.3 billion	2017	Under construction
9. Access South, Adair Southwest and Lebanon Extension (SEP)[6]	US$0.5 billion	US$0.1 billion	2017	Under construction
10. Atlantic Bridge (SEP)[6]	US$0.5 billion	US$0.2 billion	2017-2018	Under construction
11. NEXUS (SEP)[6]	US$1.1 billion	US$0.4 billion	2017 (in phases)	Pre-construction
12. High Pine[6]	$0.4 billion	$0.2 billion	2017	Under construction
13. Reliability and Maintainability (RAM) Project[6]	$0.5 billion	$0.2 billion	2017-2018 (in phases)	Under construction
14. Valley Crossing Pipeline[6]	US$1.5 billion	US$0.3 billion	2018	Under construction
15. Spruce Ridge Program [6]	$0.6 billion	No significant expenditures to date	2019	Pre-construction
16. Other - United States[6]	US$1.3 billion	US$0.8 billion	2017-2019	Various
17. Other - Canada[6]	$0.4 billion	$0.2 billion	2017-2018	Various

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
GAS DISTRIBUTION				
18. 2017 Dawn-Parkway Expansion[6] (Union Gas)	$0.6 billion	$0.5 billion	2017	Under construction
19. Other - Canada[6]	$0.3 billion	No significant expenditures to date	2017	Pre-construction
GREEN POWER AND TRANSMISSION				
20. Chapman Ranch Wind Project	US$0.4 billion	US$0.2 billion	2017	Under construction
21. Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.4 billion (£0.2 billion)	2018	Under construction
22. Hohe See Offshore Wind Project[7]	$1.7 billion (€1.07 billion)	$0.4 billion (€0.3 billion)	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 *Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to March 31, 2017.*
3 *Enbridge will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.*
4 *The Lakehead System Mainline Expansion project is funded 75% by Enbridge and 25% by EEP. As discussed under the* Line 3 Replacement Program *below, following EEP's January 27, 2017 announcement, the United States portion of the Line 3 Replacement (U.S. L3R Program) is being funded 99% by Enbridge and 1% by EEP.*
5 *As discussed under the* Line 3 Replacement Program *below, the expected cost and in-service date of this project is under review by the Company in light of the schedule for regulatory review and approval communicated by the Minnesota Public Utilities Commission (MNPUC) on October 28, 2016.*
6 *Includes projects acquired as part of the Merger Transaction. For additional information, refer to* Merger with Spectra Energy.
7 *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 EEP and the Fund Group, which is comprised of Enbridge Income Fund (the Fund), Enbridge Commercial Trust, Enbridge Income Partners LP and the subsidiaries and investees of Enbridge Income Partners LP, 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 bpd of diluent, with the potential to be further expanded to approximately 465,000 bpd of capacity with the addition of pump stations.

Bakken Pipeline System (EEP)

On February 15, 2017, EEP's joint venture with Marathon Petroleum Corporation (MPC) and MarEn Bakken Company LLC completed the acquisition of 49% interest in the holding company that owns 75% of the Bakken Pipeline System from an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. Under this arrangement, EEP and MPC would indirectly hold 75% and 25%, respectively, of the joint venture's 49% interest in the holding company of the Bakken Pipeline System. The purchase price of EEP's effective 27.6% interest in the Bakken Pipeline System was US$1.5 billion.

EEP initially funded the US$1.5 billion acquisition through a bridge loan provided by Enbridge through one of its affiliates. On April 27, 2017, a joint funding arrangement with Enbridge and its affiliates was finalized whereby Enbridge owns 75% and EEP owns 25% of EEP's effective interest in the Bakken Pipeline System. EEP also has a five-year option to acquire an additional 20% interest in the Bakken

Pipeline System at net book value. With the finalization of this joint funding arrangement, EEP repaid the US$1.5 billion outstanding under the bridge loan.

The construction of the Bakken Pipeline System is in the final stages of commissioning and is expected to begin generating cash flow during the second quarter of 2017.

Lakehead System Mainline Expansion (EEP)
The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States 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 barrels per day (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 will review all received comments and prepare a final SEIS. The Executive Order also requires that the DOS initiate 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 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 includes the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois. The expansion to increase the pipeline capacity to 1,200,000 bpd requires only the addition of pumping horsepower with no pipeline construction and is expected to cost approximately US$0.4 billion. 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 U.S. L3R Program. The expenditures incurred to date are approximately US$0.4 billion.

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 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 issue the Certificate of Public Convenience and Necessity (the Certificate) for the construction and operation of the pipeline and related facilities. Regulatory 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 (Federal Court) for leave to judicially review the Government of Canada's decision to approve the Canadian L3R Program. The Federal Court has granted leave to both MMF and AMC to proceed with a judicial review of the Government of Canada's decision to approve the Canadian L3R Program. The outcome or timing of these proceedings, including their potential impact upon the Canadian L3R Program cannot be predicted at this time.

Enbridge is in the process of complying with pre-construction conditions, all in advance of any construction that may take place in 2017.

Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (CTS).

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 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 a final Environmental Impact Statement (EIS) before Certificate of Need and Route Permit processes commence. EEP currently expects the DOC's draft EIS by mid-May 2017.

EEP will recover the costs 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 27, 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 book value until four years after the project is placed into service.

GAS PIPELINES AND PROCESSING
Sabal Trail (SEP)
Under a joint venture with NextEra Energy and Duke Energy, the Company is undertaking the Sabal Trail project, which 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 once completed will add approximately 1,100 million cubic feet per day (mmcf/d) of new capacity to access onshore shale gas supplies. The Company's 50% share of the total capital cost of the project is estimated to be approximately US$1.6 billion, with expenditures to date of approximately US$1.3 billion. The project is expected to be placed into service in the second quarter of 2017.

Access South, Adair Southwest and Lebanon Extension Projects (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 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. The total capital cost of the combined projects is estimated to be approximately US$0.5 billion, with expenditures to date of approximately US$0.1 billion. These projects are expected to be placed into service in the fourth quarter of 2017.

Atlantic Bridge Project (SEP)
SEP's Atlantic Bridge Project will transport significant and diverse natural gas supplies to the New England states and the Canadian Maritime provinces and is expected to serve as a reliable source of energy throughout the region. 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 consists of the replacement of 10 kilometres (6 miles) of 26-inch pipeline with 42-inch pipeline in New York and Connecticut; compression additions in Connecticut; a new compressor station in Massachusetts; modifications at six meter stations throughout New York, Connecticut, Massachusetts and Maine; and one new meter station in Connecticut. The total capital cost of the project is estimated to be approximately US$0.5 billion, with expenditures to date of approximately US$0.2 billion. The Connecticut portion of the project is expected to be placed into service in the fourth quarter of 2017. The New York and Massachusetts portions of the project are expected to be placed into service in late 2018.

NEXUS (SEP)
Under a joint venture with DTE Energy Company, SEP will undertake the NEXUS project, which is a new pipeline system designed to transport up to1.5 billion cubic feet per day (bcf/d) from SEP's Texas Eastern pipeline system in Ohio to the Union Gas 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. The Company's 50% share of the total capital cost of the project is estimated to be approximately US$1.1 billion, with expenditures to date of approximately US$0.4 billion. The project is expected to be placed into service in the fourth quarter of 2017, subject to the receipt of the Federal Energy Regulatory Commission's (FERC's) approval in May 2017.

High Pine
Westcoast's High Pine project on the BC Pipeline's Fort Nelson Mainline 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 total capital cost of the project is estimated to be approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. 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 BC 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 BC Pipeline system with three compressor station replacements. It will prepare the BC Pipeline system to operate at a higher load factor as higher utilization rates are expected from new incremental year-round loads. The total capital cost of the project is estimated to be approximately $0.5 billion, with expenditures to date of approximately $0.2 billion. 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 project has an estimated cost of approximately US$1.5 billion, with expenditures to date of US$0.3 billion. The Valley Crossing Pipeline is expected to be placed into service in the second half of 2018.

Spruce Ridge Program

Under the Spruce Ridge Program, Westcoast is pursuing an expansion of the BC Pipeline on the Aitken Creek Pipeline and Fort St. John mainlines 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. The project has an estimated cost of approximately $0.6 billion.There have been no significant expenditures incurred to date on this project.

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 total capital cost of this project is expected to be approximately $0.6 billion, with expenditures to date of approximately $0.5 billion and an expected in-service date in the fourth quarter of 2017.

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.

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, 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 megawatt of power. The development of these projects is subject to 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 $205 million (€142 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 March 31,	
	2017	2016
(millions of Canadian dollars)		
Canadian Mainline	**237**	309
Lakehead System	**389**	353
Regional Oil Sands System	**93**	93
Mid-Continent and Gulf Coast	**118**	181
Southern Lights Pipeline	**42**	41
Express-Platte System[1]	**27**	-
Bakken System	**32**	54
Feeder Pipelines and Other	**32**	53
Adjusted earnings before interest and income taxes	**970**	1,084
Canadian Mainline - changes in unrealized derivative fair value gain	**155**	568
Canadian Mainline - leak remediation costs	**(7)**	-
Lakehead System - changes in unrealized derivative fair value gains/(loss)	**1**	(1)
Lakehead System - hydrostatic testing	**-**	12
Lakehead System - leak remediation costs	**-**	(20)
Regional Oil Sands System - make-up rights adjustment[2]	**-**	(14)
Regional Oil Sands System - leak insurance recoveries	**3**	5
Mid-Continent and Gulf Coast - make-up rights adjustment[2]	**-**	(50)
Southern Lights Pipeline - changes in unrealized derivative fair value gain	**7**	32
Bakken System - make-up rights adjustment[2]	**-**	(3)
Bakken System - project wind-down costs	**(5)**	-
Bakken System - changes in unrealized derivative fair value gains/(loss)	**1**	(1)
Feeder Pipelines and Other - project development and transaction costs	**(1)**	-
Earnings before interest and income taxes	**1,124**	1,612

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 year reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage foreign exchange and commodity price risk inherent within the CTS.
- Canadian Mainline EBIT for the first quarter of 2017 included charges related to a crude oil release on Line 2A, which occurred in February 2017.
- Regional Oil Sands System EBIT for each period included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013.
- Southern Lights Pipeline EBIT for each period reflected 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 the first quarter of 2017 included project wind down costs related to EEP's Sandpiper Project.

Canadian Mainline

Canadian Mainline adjusted EBIT decreased in the first quarter of 2017 compared with the corresponding 2016 period, primarily due to a lower average Canadian Mainline IJT Residual Benchmark Toll and a lower foreign exchange hedge rate used to record Canadian Mainline revenues. Throughput on the mainline system was slightly higher than the first quarter of 2016 driven by continued strong oil sands production and downstream demand. Mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record throughput of 2.65 million bpd in the month of January 2017. The mainline system continued to be subject to apportionment of heavy crude oil, as nominated volumes exceeded capacity on portions of the system in the first quarter of 2017.

As noted above, a lower average Canadian Mainline IJT Residual Benchmark Toll was a key driver of the quarter-over-quarter decrease in Canadian Mainline adjusted EBIT. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher in the first quarter of 2017 due to the recovery of incremental costs associated with EEP's growth projects and surcharges to recover under collection of toll revenue in prior years. Adjusted EBIT generated by the Canadian Mainline for the balance of the year will reflect the positive effect of an increase in Canadian Mainline IJT Residual Benchmark Toll from US$1.47 to US$1.62 effective April 1, 2017.

Other factors contributing to the decrease in quarter-over-quarter adjusted EBIT included the absence of hydro test surcharge revenue on the Canadian Mainline and a lower foreign exchange hedge rate used to record Canadian Mainline revenues. The majority of the Company's foreign exchange risk on Canadian Mainline revenue is hedged. For the three months ended March 31, 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 months ended March 31, 2017 and 2016 is provided below:

March 31,	**2017**	2016
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.05**	$4.07
Lakehead System Local Toll[2]	**$2.58**	$2.44
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.47**	$1.63

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.*

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.*

Throughput Volume

	Three months ended March 31,	
	2017	2016
(thousands of bpd)		
Average throughput volume[1]	**2,593**	2,543

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 increased for the three months ended March 31, 2017 compared with the corresponding 2016 period. The quarter-over-quarter increase in adjusted EBIT reflected stronger operating performance driven by a higher long-haul volume throughput, higher Lakehead System Local Tolls and surcharge revenue. These positive impacts were partially offset by a lower average United States to Canadian dollar exchange rate (Average Exchange Rate) in the first quarter of 2017 compared with the corresponding 2016 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$294 million for the three months ended March 31, 2017 compared with US$256 million for the three months ended March 31, 2016. The quarter-over-quarter increase reflected higher throughput and the higher Lakehead System Local Toll. As discussed under *Canadian Mainline* above, higher throughput on the Lakehead System in the first quarter of 2017 also reflected strong downstream demand. Partially offsetting the increase in adjusted EBIT were higher depreciation expense from an increased asset base, incremental power costs associated with higher throughput and higher property taxes.

As noted above, partially offsetting the quarter-over-quarter increase in Lakehead System adjusted EBIT was the unfavourable effect of translating United States dollar earnings at a lower Average Exchange Rate of $1.32 for the three months ended March 31, 2017, compared with an Average Exchange Rate of $1.37 for 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 and 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 March 31,	
	2017	2016
(thousands of bpd)		
Average throughput volume[1]	**2,748**	2,735

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

Mid-Continent and Gulf Coast
Mid-Continent and Gulf Coast adjusted EBIT decreased in the first quarter of 2017 compared with the corresponding 2016 period. The quarter-over-quarter decrease in adjusted EBIT reflected lower contributions from Flanagan South Pipeline (Flanagan South) and Ozark Pipeline, as well as the unfavourable effect of translating United States dollar earnings to Canadian dollars at a lower Average Exchange Rate in the first quarter of 2017 compared with the corresponding 2016 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$90 million for the three months ended March 31, 2017 compared with US$132 million for the three months ended March 31, 2016. The decrease in adjusted EBIT primarily reflected lower contributions from Flanagan South related to the change in recognition of make-up rights for adjusted EBIT purposes, as well as higher operating and administrative expenses.

Mid-Continent and Gulf Coast EBIT for prior periods included make-up rights adjustments to recognize revenue for certain long-term take-or-pay contracts rateably over the contract life. 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 quarter of 2017 compared with the first quarter 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. This negative effect on adjusted EBIT for the first quarter of 2017 was partially offset by higher revenues on Flanagan South due to higher throughput during the first quarter of 2017.

The quarter-over-quarter decrease in Mid-Continent and Gulf Coast adjusted EBIT also reflected lower throughput on the Ozark Pipeline, a non-core pipeline which was sold to a third party on March 1, 2017. For additional information, refer to *Recent Developments – Liquids Pipelines – Disposition of Ozark Pipeline Asset.*

As noted above, partially contributing to the quarter-over-quarter decrease in adjusted EBIT was the unfavourable effect of translating United States dollar earnings at a lower Average Exchange Rate in the first quarter of 2017. 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 Other. For further details refer to *Eliminations and Other*.

Express-Platte
The Express-Platte pipeline system, an approximately 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, held through its investment in SEP. SEP is a natural gas and crude oil infrastructure master limited partnership that is publicly traded on the New York Stock Exchange under the symbol "SEP." Enbridge has a 75% equity interest 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 first quarter of 2017 reflects results of operations since the completion of the Merger Transaction on February 27, 2017.

Express-Platte results include higher crude oil transportation revenues due to higher volumes on the Express and Platte pipelines, higher tariff rates on the Express pipeline, and 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 in the first quarter of 2017 compared with the corresponding 2016 period. The quarter-over-quarter decrease in adjusted EBIT reflected lower rates and lower rail revenues on the United States portion of the Bakken System owned by EEP, as well as the negative impact of translating United States dollar earnings to Canadian dollars at a lower Average Exchange Rate in the first quarter of 2017, compared with the corresponding 2016 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Bakken System adjusted EBIT was US$20 million for the three months ended March 31, 2017 compared with US$37 million for the corresponding 2016 period. The decrease in quarter-over-quarter adjusted EBIT 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 well as lower revenues from EEP's Berthold rail facility due to expired contracts.

As noted above, impacting quarter-over-quarter adjusted EBIT was the unfavourable effect of translating United States dollar earnings at a lower Average Exchange Rate in the first 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 in the first quarter of 2017 compared with the corresponding 2016 period. The quarter-over-quarter decrease primarily reflected the absence of EBIT from the South Prairie Region assets that were sold in December 2016 and the absence of EBIT from Eddystone Rail Company, L.L.C. (Eddystone Rail) that was impaired in the second quarter of 2016.

GAS PIPELINES AND PROCESSING

Earnings Before Interest and Income Taxes

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
US Gas Transmission[1]	**207**	-
Canadian Midstream[2]	**51**	21
Alliance Pipeline	**57**	49
US Midstream[3,4]	**(7)**	(1)
Other[5]	**28**	18
Adjusted earnings before interest and income taxes	**336**	87
US Gas Transmission - inspection, repair and other costs	**(2)**	-
US Gas Transmission - project development and transaction costs	**(2)**	-
Canadian Midstream - project development and transaction costs	**(1)**	-
Alliance Pipeline - changes in unrealized derivative fair value gain	**2**	12
US Midstream - changes in unrealized derivative fair value gains/(loss)	**8**	(38)
US Midstream - DCP mark-to-market adjustment	**(2)**	-
Earnings before interest and income taxes	**339**	61

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 BC 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 reflected 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 held through 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. 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, which is owned 78% by Enbridge (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. New projects placed into service may initially have higher levels of interruptible services at inception. 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.

Asset Utilization
Gas supply and demand dynamics continue to change as a result of the development of nonconventional 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 over-supply of pipeline takeaway capacity in these 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 on 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 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 first quarter of 2017 reflects results of operations since the completion of the Merger Transaction on February 27, 2017. US Gas Transmission’s operating results include higher revenues 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 BC Pipeline & Field Services, Spectra Canadian Midstream, M&N Canada and certain other gas pipeline, gathering and storage assets. BC Pipeline and BC Field Services provide fee-based natural gas transmission and gas gathering and processing services. BC Pipeline has approximately 2,816 kilometres (1,750 miles) of transmission pipeline in British Columbia (B.C.) and Alberta, as well as associated mainline compressor stations. The BC Field Services business includes eight gas processing plants located in B.C., associated field compressor stations and approximately 2,253 kilometres (1,400 miles) of gathering pipelines. Spectra Canadian Midstream provides similar gas gathering and processing services in B.C. 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 Canadian Midstream 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. BC 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 assets. 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 provides 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 BC 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 first quarter of 2017 reflected the results of operations from the new assets acquired through the Merger Transaction as described above. The quarter-over-quarter increase in Canadian Midstream adjusted EBIT also reflected contributions from the Tupper Plants acquired in April 2016.

Canadian Midstream results include higher interruptible revenues and incremental revenues from volumes that exceeded take or pay levels due to robust producer activity within Canadian Midstream's footprint. These higher revenues were partially offset by an increase in operating and maintenance costs and unplanned outages at two BC processing plants.

Alliance Pipeline

Alliance Pipeline adjusted EBIT for the three months ended March 31, 2017, which comprises equity earnings from the Company's 50% equity investment in Alliance Pipeline, increased compared with the first quarter of 2016, primarily due to higher revenues resulting from strong demand for seasonal firm service.

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 March 31, 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 during the first quarter of 2017 compared with the corresponding 2016 quarter. The quarter-over-quarter increase in adjusted loss before interest and income taxes was primarily attributable to lower volumes on the Company’s US Midstream assets that are held through EEP, as a result of 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 $5 million to US Midstream adjusted EBIT during the quarter.

Other

Other adjusted EBIT increased in the first quarter of 2017 compared with the first quarter of 2016, primarily reflecting positive contributions from Offshore due to higher revenues resulting from an increase in transportation rates on Heidelberg Oil Pipeline.

GAS DISTRIBUTION

Earnings Before Interest and Income Taxes

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**138**	175
Union Gas Limited (Union Gas)[1]	**63**	-
Noverco Inc. (Noverco)	**37**	38
Other Gas Distribution and Storage	**31**	27
Adjusted earnings before interest and income taxes	**269**	240
EGD - (warmer)/colder than normal weather[2]	**-**	(17)
Noverco - changes in unrealized derivative fair value gains/(loss)	**10**	(1)
Noverco - recognition of regulatory balances	**-**	17
Union Gas - employee severance and restructuring costs	**(4)**	-
Earnings before interest and income taxes	**275**	239

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 makes such an adjustment to its EBIT.*

Additional details on items impacting Gas Distribution EBIT include:

- EGD EBIT for each period includes the impact of warmer/colder than normal weather in EGD’s franchise area. Prior to January 1, 2017, the impacts of warmer/colder than normal weather were removed for the purpose of calculating EGD’s adjusted EBIT. Effective January 1, 2017, the Company no longer makes such an adjustment to 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 March 31,	
	2017	2016
(millions of Canadian dollars)		
Adjusted earnings before interest and income taxes	**138**	175
Interest expense	**(46)**	(37)
Income taxes expense	**(10)**	(20)
Adjusting items in respect of:		
Interest expense	**1**	-
Income taxes	**-**	(4)
Adjusted earnings	**83**	114
EGD - warmer than normal weather	**-**	(13)
Earnings attributable to common shareholders	**83**	101

EGD adjusted earnings decreased for the three months ended March 31, 2017 compared with the corresponding 2016 period, primarily due to the change in recognition of warmer/colder than normal weather for adjusted earnings purposes. EGD earnings for each period included the impact of warmer/colder than normal weather in EGD's franchise area. A significant portion of EGD's gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the flow-through nature of these costs. As noted above, 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 the above noted treatment for the purposes of adjusted earnings, and as such, the quarter-over-quarter decrease in EGD adjusted earnings reflected lower distribution revenues due to the impacts of warmer than normal weather during the winter months in the first quarter of 2017. If for the three months ended March 31, 2017 the Company continued with the above noted treatment, EGD adjusted earnings would have increased by $21 million.

Other factors contributing to a quarter-over-quarter decrease in EGD adjusted earnings were higher earnings sharing in 2017, higher depreciation expense resulting from a higher overall asset base and lower capitalized interest resulting from the completion of the Greater Toronto Area project in March 2016.

Union Gas
Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience 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.

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 first quarter of 2017 reflects its results of operations since the completion of the Merger Transaction on February 27, 2017.

Union Gas' results include higher distribution and transportation revenues from rate increases due to expansion projects being placed into service at the end of 2016. These higher revenues were partially offset by an increase in operating and maintenance costs.

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 March 31,	**2017**
(millions of Canadian dollars)	
Adjusted earnings before interest and income taxes	**63**
Interest expense	**(15)**
Income taxes recovery	**15**
Adjusting items in respect of:	
Income taxes	**(1)**
Earnings attributable to noncontrolling interests	**(1)**
Adjusted earnings	**61**
Employee severance costs adjustment	**(3)**
Earnings attributable to common shareholders	**58**

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

GREEN POWER AND TRANSMISSION
Earnings Before Interest and Income Taxes

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Green Power and Transmission	**50**	48
Adjusted earnings before interest and income taxes	**50**	48
Green Power and Transmission - changes in unrealized derivative fair value gain	**-**	1
Earnings before interest and income taxes	**50**	49

Green Power and Transmission adjusted EBIT for the three months ended March 31, 2017 reflected the impact of projects that came into service in 2016; however, due to weaker wind resources in the first quarter of 2017, adjusted EBIT remained comparable quarter-over-quarter.

ENERGY SERVICES
Earnings Before Interest and Income Taxes

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Energy Services	**(5)**	1
Adjusted earnings/(loss) before interest and income taxes	**(5)**	1
Energy Services - changes in unrealized derivative fair value gains/(loss)	**161**	(7)
Earnings/(loss) before interest and income taxes	**156**	(6)

Following are additional details on items impacting Energy Services EBIT:

- 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.

Weak Energy Services performance in the first quarter of both 2017 and 2016 reflected decreased crude oil storage opportunities, lower refinery demand and compressed location and quality differentials in certain markets. 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 March 31,	
	2017	2016
(millions of Canadian dollars)		
Operating and administrative	**(40)**	(15)
Realized foreign exchange derivative loss	**(72)**	(87)
Other	**7**	16
Adjusted loss before interest and income taxes	**(105)**	(86)
Changes in unrealized derivative fair value gains	**71**	367
Unrealized intercompany foreign exchange loss	**(7)**	(60)
Project development and transaction costs	**(149)**	-
Employee severance and restructuring costs	**(125)**	-
Earnings/(loss) before interest and income taxes	**(315)**	221

Items impacting Eliminations and Other EBIT include:

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

Included in Eliminations and Other adjusted loss before interest and income taxes for the three months ended March 31, 2017 was a realized loss of $72 million (2016 - $87 million) 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 denominated earnings from its United States operations utilizing foreign exchange derivative contracts with the objective of enhancing the predictability of its Canadian dollar earnings.

The notional amount of foreign currency derivatives realized during the first quarter of 2017 was US$264 million (2016 - US$261 million) with an average price to sell United States dollars for Canadian dollars at $1.05 (2016 - $1.04). The Average Exchange Rate for the three months ended March 31, 2017 was $1.32 (2016 - $1.37). As the hedged rate was lower than the Average Exchange Rate in each of the first quarters of 2017 and 2016, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for the first quarter of 2017 was less than the comparative 2016 period due to a 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 of $1.32 for the first quarter of 2017 (2016 - $1.37) 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.

Eliminations and Other adjusted EBIT also reflected higher operating and administrative costs in the first quarter of 2017 due to higher information technology and other centralized service costs post integration with Spectra Energy and proportionally lower recoveries from business units during the quarter.

Other adjusted EBIT decreased in the first quarter of 2017 compared with the corresponding 2016 period and reflected realized foreign exchange losses from the translation of certain intercompany transactions.

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.

Spectra Energy Partners has US$2.2 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 March 31, 2017 and December 31, 2016.

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

1 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
2 *Committed credit facility acquired as part of merger with Spectra Energy. For additional information, refer to* Merger with Spectra Energy.

During the three months ended March 31, 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 March 31, 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 maintains $566 million (December 31, 2016 - $335 million) of uncommitted demand facilities, of which $171 million (December 31, 2016 - $177 million) were unutilized as at March 31, 2017.

The Company’s net available liquidity of $14,517 million as at March 31, 2017 was inclusive of $1,855 million of unrestricted cash and cash equivalents and net of bank indebtedness of $836 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 March 31, 2017, the Company was deemed to be 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 March 31, 2017, the Company’s debt capitalization ratio was 47.8% 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.

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 $175 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 and the Fund Group are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP 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 March 31, 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 March 31, 2017, the Company's net available liquidity totalled $14,517 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 March 31,	
	2017	2016
(millions of Canadian dollars)		
Operating activities	**1,677**	1,861
Investing activities	**(3,523)**	(1,852)
Financing activities	**1,593**	751
Effect of translation of foreign denominated cash and cash equivalents	**(9)**	(40)
Increase/(decrease) in cash and cash equivalents	**(262)**	720

Significant sources and uses of cash for the three months ended March 31, 2017 and March 31, 2016 are summarized below:

Operating Activities

- The cash flows delivered by operations in the first quarter of 2017 reflect operating factors discussed under *Non-GAAP Measures – Adjusted EBIT and Non-GAAP Measures – Adjusted Earnings*, which included contributions from new assets following the completion of the Merger Transaction on February 27, 2017. These additional contributions quarter-over-quarter were more than offset by a decrease in contribution from the Liquids Pipelines segment, mainly attributable to a lower average Canadian Mainline IJT Residual Benchmark Toll and a lower foreign exchange hedge rate used to record Canadian Mainline revenues.
- In the first quarter of 2017, 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, also contributed to lower cash flows from operations when compared with the corresponding 2016 period.
- Changes in operating assets and liabilities included within operating activities were $237 million (2016 - $131 million) for the three months ended March 31, 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 quarter of 2017.

Investing Activities

- The quarter-over-quarter increase in cash used in investing activities was primarily attributable to higher spending on the Company's equity investments. During the first quarter of 2017, the Company paid cash consideration of $1.96 billion (US $1.5 billion) for the acquisition of an interest in the Bakken Pipeline System. In addition, the Company also made an initial equity investment of $0.4 billion in connection with its 50% interest in the Hohe See Offshore Wind Project
- Also, during the first quarter of 2017, the Company's investment in intangible assets was higher compared with the corresponding 2016 period.
- The above increase in cash usage was partially offset by cash acquired in the Merger Transaction, as well as proceeds from the disposition of the Ozark Pipeline assets in the first quarter 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.
- Finally, the Company continues with the 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.

Financing Activities

- During the first quarter of 2017, excluding the impact of the Merger Transaction, the Company's overall debt increased by $2,045 million compared with a decrease of $921 million for the comparable 2016 period, mainly to finance its growth capital program and maturing term debt.
- The quarter-over-quarter increase in cash generated from financing activities also reflected higher cash contributions from noncontrolling interests, which now also include noncontrolling interests in the assets acquired through the Merger Transaction.
- The above increases in cash quarter-over-quarter were partially offset by a 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.
- The Company's common share dividend payments also increased in the first quarter of 2017, primarily due to the increase in the common share dividend rate effective March 2017 and higher number of common shares outstanding due to the issuance of approximately 75 million common shares in 2016.

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 March 31, 2017, dividends declared were $548 million (2016 - $460 million), of which $354 million (2016 - $276 million) were paid in cash and reflected in financing activities. The remaining $194 million (2016 - $184 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 months ended March 31, 2017 and 2016, 35.4% and 40.0%, respectively, of total dividends declared were reinvested.

On May 4, 2017, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2017 to shareholders of record on May 15, 2017.

Common Shares	$0.61000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
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

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
On February 2, 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. On March 16, 2017, the defendants filed motions to dismiss on all counts. Eddystone Rail is defending the motions. Results of operations from Eddystone Rail are reported within *Liquids Pipelines – Feeder Pipelines and Other*.

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 March 31, 2017, EEP's total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge) including those costs that were considered probable and that could be reasonably estimated at March 31, 2017. Despite the efforts EEP has made to ensure the reasonableness of its estimate, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies.

Line 6A Crude Oil Release
A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP has completed the cleanup, remediation and restoration of the areas affected by the release. The total estimated cost for the Line 6A crude oil release was approximately US$53 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at March 31, 2017, EEP has no remaining estimated liability.

Insurance Recoveries
EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. As at December 31, 2016, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the

US$650 million applicable limit. Of the remaining US$103 million coverage limit, US$85 million was the subject matter of a lawsuit against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. On May 2, 2017 the arbitration panel issued a decision that was not favourable to Enbridge. As a result, EEP is unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

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

Line 6A and 6B Fines and Penalties

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

Consent Decree

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

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

British Columbia Pipeline T-South System

On April 25, 2017, Enbridge launched a binding open season on its British Columbia Pipeline T-South system for delivery of an incremental 190 mmcf/day of natural gas into the Huntington/Sumas market at the Canadian/United States border. The system is currently fully contracted and an expansion is necessary to meet increasing customer demand as a result of rapidly growing production in the prolific Montney and Duvernay regions. The project would include looping of T-South and upgrades at compressor stations along the pipeline system at a cost of approximately $1 billion. Subject to the outcome of the open season, the project could be brought into service by late 2020.

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) from the United States 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 $4,419 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 and pay floating-receive fixed interest rate swaps and options are used to hedge against the effect of future

interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.4% and fixed to floating interest rate swaps with an average swap rate of 2.1%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate 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 3.7%.

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

Commodity Price Risk
The Company's earnings and cash flows are exposed to changes in commodity prices as a result of its ownership 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 CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(2)**	(35)
Interest rate contracts	**(14)**	(576)
Commodity contracts	**21**	16
Other contracts	**(9)**	31
Net investment hedges		
Foreign exchange contracts	**8**	84
	4	(480)
Amount of (gains)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Foreign exchange contracts[1]	**1**	3
Interest rate contracts[2]	**48**	(21)
Commodity contracts[3]	**(2)**	(8)
Other contracts[4]	**9**	(26)
	56	(52)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**2**	26
	2	26
Amount of unrealized gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts[1]	**273**	1,016
Interest rate contracts[2]	**(18)**	4
Commodity contracts[3]	**163**	(184)
Other contracts[4]	**-**	6
	418	842

1 *Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

Fair Value Derivatives

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

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 March 31, 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 and 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 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

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 derecogntion 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.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the statement of financial position and disclosing additional key information about lease agreements. 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 is currently assessing which transition method to use.

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 also developing processes to generate the disclosures required under the new standard.

QUARTERLY FINANCIAL INFORMATION

	2017	2016				2015		
	Q1[2]	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**11,146**	9,338	8,488	7,939	8,795	8,914	8,320	8,631
Earnings/(loss) attributable to common shareholders	**638**	365	(103)	301	1,213	378	(609)	577
Earnings/(loss) per common share	**0.54**	0.39	(0.11)	0.33	1.38	0.44	(0.72)	0.68
Diluted earnings/(loss) per common share	**0.54**	0.39	(0.11)	0.33	1.38	0.44	(0.72)	0.67
Dividends per common share	**0.583**	0.530	0.530	0.530	0.530	0.465	0.465	0.465
Changes in unrealized derivative fair value (gains)/loss[1]	**(245)**	189	32	1	(652)	45	654	(296)

1 *Included in earnings/(loss) attributable to common shareholders.*
2 *Included in the first quarter 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 which 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 Enbridge Income Partners L.P. 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.
- Included in the second quarter of 2015 was a goodwill impairment charge of $440 million ($167 million after-tax attributable to Enbridge) related to EEP's natural gas and NGL businesses due to a prolonged decline in commodity prices which reduced producers' expected drilling programs and negatively impacted volumes on EEP's natural gas and NGL systems.

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]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	20,000,000	June 1, 2017	Series C
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, 2017	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)	1,638,832,021
Stock Options - issued and outstanding (25,327,699 vested)	40,466,405

1 *Outstanding share data information is provided as at April 28, 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 all 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.*

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

March 31, 2017

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2017	2016
(unaudited; millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**6,866**	4,804
Gas distribution sales	**1,363**	1,007
Transportation and other services	**2,917**	2,984
	11,146	8,795
Expenses		
Commodity costs	**6,550**	4,711
Gas distribution costs	**1,015**	754
Operating and administrative	**1,541**	1,080
Depreciation and amortization	**672**	559
Environmental costs, net of recoveries	**10**	17
	9,788	7,121
	1,358	1,674
Income from equity investments	**236**	226
Other income	**35**	276
Interest expense	**(486)**	(412)
	1,143	1,764
Income taxes *(Note 11)*	**(198)**	(417)
Earnings	**945**	1,347
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(224)**	(61)
Earnings attributable to Enbridge Inc.	**721**	1,286
Preference share dividends	**(83)**	(73)
Earnings attributable to Enbridge Inc. common shareholders	**638**	1,213
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*	**0.54**	1.38
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*	**0.54**	1.38

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2017	2016
(unaudited; millions of Canadian dollars)		
Earnings	**945**	1,347
Other comprehensive income/(loss), net of tax		
Change in unrealized loss on cash flow hedges	**(2)**	(443)
Change in unrealized gains on net investment hedges	**49**	394
Other comprehensive income/(loss) from equity investees	**6**	(2)
Reclassification to earnings of realized cash flow hedges	**45**	(10)
Reclassification to earnings of unrealized cash flow hedges	**(4)**	9
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**4**	2
Change in foreign currency translation adjustment	**432**	(1,377)
Other comprehensive income/(loss), net of tax	**530**	(1,427)
Comprehensive income/(loss)	**1,475**	(80)
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(374)**	100
Comprehensive income attributable to Enbridge Inc.	**1,101**	20
Preference share dividends	**(83)**	(73)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**1,018**	(53)

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31,	
	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	**37,428**	-
Dividend reinvestment and share purchase plan	**194**	184
Shares issued on exercise of stock options	**33**	12
Balance at end of period	**48,147**	9,828
Additional paid-in capital		
Balance at beginning of period	**3,399**	3,301
Stock-based compensation	**35**	22
Fair value of outstanding earned stock based compensation from Merger Transaction	**77**	-
Options exercised	**(49)**	(5)
Dilution loss and other	**(36)**	(3)
Balance at end of period	**3,426**	3,315
Retained earnings/(deficit)		
Balance at beginning of period	**(716)**	142
Earnings attributable to Enbridge Inc.	**721**	1,286
Preference share dividends	**(83)**	(73)
Common share dividends declared	**(548)**	(460)
Dividends paid to reciprocal shareholder	**7**	6
Redemption value adjustment attributable to redeemable noncontrolling interests	**152**	(118)
Adjustment for the recognition of unutilized tax deductions for stock based compensation expense	**41**	-
Adjustment relating to equity method investment	**-**	(29)
Balance at end of period	**(426)**	754
Accumulated other comprehensive income/(loss) *(Note 9)*		
Balance at beginning of period	**1,058**	1,632
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**380**	(1,266)
Balance at end of period	**1,438**	366
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	**59,738**	20,676
Noncontrolling interests		
Balance at beginning of period	**577**	1,300
Earnings attributable to noncontrolling interests	**192**	7
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	**(1)**	(91)
Change in foreign currency translation adjustment	**141**	(55)
Reclassification to earnings of realized cash flow hedges	**10**	1
Reclassification to earnings of unrealized cash flow hedges	**-**	2
	150	(143)
Comprehensive income/(loss) attributable to noncontrolling interests	**342**	(136)
Noncontrolling interests resulting from Merger Transaction	**8,792**	-
Enbridge Energy Company Inc. common control transaction	**43**	-
Distributions	**(191)**	(184)
Contributions	**215**	16
Other	**3**	(6)
Balance at end of period	**9,781**	990
Total equity	**69,519**	21,666
Dividends paid per common share	**0.583**	0.530

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31, 2017	2016
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**945**	1,347
Depreciation and amortization	**672**	559
Deferred income taxes expense	**161**	374
Changes in unrealized gains on derivative instruments, net *(Note 10)*	**(418)**	(842)
Cash distributions less than equity earnings	**(22)**	(40)
Gains on disposition	**(14)**	-
Hedge ineffectiveness	**1**	26
Inventory revaluation allowance	**7**	168
Unrealized loss on intercompany loan	**6**	60
Other	**98**	87
Changes in environmental liabilities, net of recoveries	**4**	(9)
Changes in operating assets and liabilities	**237**	131
	1,677	1,861
Investing activities		
Additions to property, plant and equipment	**(1,642)**	(1,645)
Joint venture financing	**(39)**	(10)
Long-term investments	**(2,511)**	(133)
Cash distributions in excess of equity earnings	**11**	-
Restricted long-term investments	**(15)**	(12)
Additions to intangible assets	**(233)**	(27)
Deposit for acquisition	**-**	(54)
Cash acquired in Merger Transaction *(Note 4)*	**614**	-
Proceeds from disposition	**289**	-
Affiliate loans, net	**(2)**	2
Changes in restricted cash	**5**	27
	(3,523)	(1,852)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**260**	243
Net change in commercial paper and credit facility draws	**2,285**	(1,164)
Debenture and term note repayments	**(500)**	-
Contributions from noncontrolling interests	**215**	16
Distributions to noncontrolling interests	**(191)**	(184)
Contributions from redeemable noncontrolling interests	**11**	4
Distributions to redeemable noncontrolling interests	**(54)**	(42)
Common shares issued	**4**	2,227
Preference share dividends	**(83)**	(73)
Common share dividends	**(354)**	(276)
	1,593	751
Effect of translation of foreign denominated cash and cash equivalents	**(9)**	(40)
Increase/(decrease) in cash and cash equivalents	**(262)**	720
Cash and cash equivalents at beginning of period	**2,117**	1,015
Cash and cash equivalents at end of period	**1,855**	1,735

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2017	December 31, 2016
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,855**	2,117
Restricted cash	**175**	68
Accounts receivable and other *(Note 5)*	**6,627**	4,978
Accounts receivable from affiliates	**40**	14
Inventory	**1,205**	1,233
	9,902	8,410
Property, plant and equipment, net	**99,518**	64,284
Long-term investments	**14,460**	6,836
Restricted long-term investments	**243**	90
Deferred amounts and other assets	**6,066**	3,113
Intangible assets, net	**3,838**	1,573
Goodwill	**35,300**	78
Deferred income taxes	**1,202**	1,170
Assets held for sale	**-**	278
	170,529	85,832
Liabilities and equity		
Current liabilities		
Bank indebtedness	**836**	623
Short-term borrowings	**833**	351
Accounts payable and other	**8,398**	7,295
Accounts payable to affiliates	**128**	122
Interest payable	**628**	333
Environmental liabilities	**143**	142
Current maturities of long-term debt *(Note 7)*	**4,343**	4,100
	15,309	12,966
Long-term debt *(Note 7)*	**60,736**	36,494
Other long-term liabilities	**7,009**	4,981
Deferred income taxes	**14,717**	6,036
	97,771	60,477
Contingencies *(Note 15)*		
Redeemable noncontrolling interests	**3,239**	3,392
Equity		
Share capital *(Note 8)*		
Preference shares	**7,255**	7,255
Common shares *(1,639 and 943 outstanding at March 31, 2017 and December 31, 2016, respectively)*	**48,147**	10,492
Additional paid-in capital	**3,426**	3,399
Deficit	**(426)**	(716)
Accumulated other comprehensive income *(Note 9)*	**1,438**	1,058
Reciprocal shareholding	**(102)**	(102)
Total Enbridge Inc. shareholders' equity	**59,738**	21,386
Noncontrolling interests	**9,781**	577
	69,519	21,963
	170,529	85,832

Variable Interest Entities (Note 6)

See accompanying notes to the unaudited interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2016 filed on February 17, 2017. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the Company's financial position as at March 31, 2017 and results of operations and cash flows for the three months ended March 31, 2017 and 2016. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's consolidated financial statements as at and for the year ended December 31, 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.

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 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
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 derecogntion 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.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the statement of financial position and disclosing additional key information about lease agreements. 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 is currently assessing which transition method to use.

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 also developing processes to generate the disclosures required under the new standard.

3. SEGMENTED INFORMATION

Three months ended March 31, 2017	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,155**	**1,235**	**1,584**	**137**	**6,133**	**(98)**	**11,146**
Commodity and gas distribution costs	**(3)**	**(647)**	**(1,046)**	**1**	**(5,968)**	**98**	**(7,565)**
Operating and administrative	**(750)**	**(254)**	**(189)**	**(40)**	**(12)**	**(296)**	**(1,541)**
Depreciation and amortization	**(356)**	**(136)**	**(112)**	**(51)**	**-**	**(17)**	**(672)**
Environmental costs, net of recoveries	**(10)**	**-**	**-**	**-**	**-**	**-**	**(10)**
	1,036	**198**	**237**	**47**	**153**	**(313)**	**1,358**
Income from equity investments	**86**	**110**	**36**	**2**	**2**	**-**	**236**
Other income	**2**	**31**	**2**	**1**	**1**	**(2)**	**35**
Earnings/(loss) before interest and income taxes	**1,124**	**339**	**275**	**50**	**156**	**(315)**	**1,629**
Interest expense							**(486)**
Income taxes							**(198)**
Earnings							**945**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							**(224)**
Preference share dividends							**(83)**
Earnings attributable to Enbridge Inc. common shareholders							**638**
Additions to property, plant and equipment[1]	**654**	**655**	**183**	**114**	**-**	**59**	**1,665**

Three months ended March 31, 2016	Liquids Pipelines	Gas Pipelines and Processing	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	2,613	652	1,166	134	4,311	(81)	8,795
Commodity and gas distribution costs	(2)	(483)	(766)	1	(4,296)	81	(5,465)
Operating and administrative	(766)	(119)	(134)	(40)	(15)	(6)	(1,080)
Depreciation and amortization	(346)	(74)	(80)	(48)	-	(11)	(559)
Environmental costs, net of recoveries	(17)	-	-	-	-	-	(17)
	1,482	(24)	186	47	-	(17)	1,674
Income/(loss) from equity investments	113	70	43	2	(2)	-	226
Other income/(expense)	17	15	10	-	(4)	238	276
Earnings/(loss) before interest and income taxes	1,612	61	239	49	(6)	221	2,176
Interest expense							(412)
Income taxes							(417)
Earnings							1,347
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							(61)
Preference share dividends							(73)
Earnings attributable to Enbridge Inc. common shareholders							1,213
Additions to property, plant and equipment[1]	1,332	52	248	7	-	6	1,645

1 Includes allowance for equity funds used during construction.

TOTAL ASSETS

(unaudited; millions of Canadian dollars)	**March 31, 2017** [1]	December 31, 2016
Liquids Pipelines	**57,029**	52,043
Gas Pipelines and Processing	**47,205**	11,182
Gas Distribution	**18,975**	10,204
Green Power and Transmission	**5,516**	5,571
Energy Services	**1,970**	1,951
Eliminations and Other	**4,612**	4,881
	135,307	85,832

1 Excludes goodwill allocation of $35.2 billion, in connection with the Merger Transaction (Note 4).

4. ACQUISITIONS AND DISPOSITION

ACQUISITIONS

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, 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 U.S. producers to refineries in the U.S. 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 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 is $1,191 million, of which $16 million is not expected to be collected, is included in current assets.

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

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

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

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

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

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

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

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

Upon completion of the Merger Transaction, the Company began consolidating Spectra Energy. Since the closing date through March 31, 2017, Spectra Energy has generated approximately $736 million in revenues and $32 million in earnings.

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

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

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

Bakken Pipeline System

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

The purchase price was allocated as follows:

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

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

The Company's equity investment includes the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date, which is comprised of $19 million in goodwill and $1,219 million in amortizable assets included within the Liquids Pipelines segment.

Hohe See Offshore Wind Project

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

DISPOSITION

Ozark Pipeline

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

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain EEP subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$275 million ($366 million) and US$355 million ($477 million) as at March 31, 2017 and December 31, 2016, respectively.

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

6. VARIABLE INTEREST ENTITIES

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

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

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

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

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

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

ACQUIRED UNCONSOLIDATED VARIABLE INTEREST ENTITIES
The following unconsolidated VIEs are included within Long-term investments in the table above.

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

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

7. DEBT

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

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

1 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
2 *These facilities were acquired on February 27, 2017 in conjunction with the Merger Transaction (Note 4).*

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

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

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2017 to 2022.

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

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

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

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

8. SHARE CAPITAL

COMMON SHARES

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

1 2016 - Gross proceeds $2,300 million; net issuance costs $59 million.
2 Common shares valued at $37,429 million were issued in the Merger Transaction (Note 4); net issuance costs were $1 million.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 13 million (2016 - 12 million) for the three months ended March 31, 2017, resulting from the Company's reciprocal investment in Noverco Inc.

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

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

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

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income/(loss) (AOCI) attributable to Enbridge Inc. common shareholders for the three months ended March 31, 2017 and 2016 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2017	**(746)**	**(629)**	**2,700**	**37**	**(304)**	**1,058**
Other comprehensive income/(loss) retained in AOCI	**(1)**	**50**	**293**	**5**	**-**	**347**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**31**	**-**	**-**	**-**	**-**	**31**
Commodity contracts[2]	**(2)**	**-**	**-**	**-**	**-**	**(2)**
Foreign exchange contracts[3]	**-**	**-**	**-**	**-**	**-**	**-**
Other contracts[4]	**9**	**-**	**-**	**-**	**-**	**9**
Amortization of pension and OPEB actuarial loss and prior service cost[5]	**-**	**-**	**-**	**-**	**6**	**6**
	37	**50**	**293**	**5**	**6**	**391**
Tax impact						
Income tax on amounts retained in AOCI	**(1)**	**(1)**	**-**	**1**	**-**	**(1)**
Income tax on amounts reclassified to earnings	**(8)**	**-**	**-**	**-**	**(2)**	**(10)**
	(9)	**(1)**	**-**	**1**	**(2)**	**(11)**
Balance at March 31, 2017	**(718)**	**(580)**	**2,993**	**43**	**(300)**	**1,438**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2016	(688)	(795)	3,365	37	(287)	1,632
Other comprehensive income/(loss) retained in AOCI	(459)	409	(1,314)	(8)	-	(1,372)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	29	-	-	-	-	29
Commodity contracts[2]	(3)	-	-	-	-	(3)
Foreign exchange contracts[3]	2	-	-	-	-	2
Other contracts[4]	(26)	-	-	-	-	(26)
Amortization of pension and OPEB actuarial loss and prior service cost[5]	-	-	-	-	3	3
	(457)	409	(1,314)	(8)	3	(1,367)
Tax impact						
Income tax on amounts retained in AOCI	118	(15)	-	6	-	109
Income tax on amounts reclassified to earnings	(7)	-	-	-	(1)	(8)
	111	(15)	-	6	(1)	101
Balance at March 31, 2016	(1,034)	(401)	2,051	35	(285)	366

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
3 *Reported within Other income in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

10. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

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

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

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating and pay floating-receive fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.4% and fixed to floating interest rate swaps with an average swap rate of 2.1%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3.7%.

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

Commodity Price Risk

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

Emission Allowance Price Risk

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

Equity Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

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

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

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

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

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

March 31, 2017	2017	2018	2019	2020	2021	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**1,069**	**2**	**2**	**2**	**-**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**3,911**	**2,770**	**2,945**	**2,723**	**567**	**224**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**89**	**6**	**-**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**89**	**25**	**27**	**144**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**149**	**256**	**340**	**-**	**-**	**-**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**-**	**-**	**-**	**35**	**152**	**952**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**-**	**-**	**32,662**	**-**	**-**	**20,000**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**4,828**	**5,137**	**1,571**	**152**	**100**	**299**
Interest rate contracts - long-term receive fixed rate *(millions of Canadian dollars)*	**1,390**	**1,302**	**900**	**671**	**345**	**320**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**3,982**	**2,736**	**767**	**-**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**48**	**40**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(111)**	**(26)**	**20**	**-**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**4**	**(9)**	**-**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(3)**	**(8)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**42**	**30**	**31**	**35**	**(3)**	**(43)**

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

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

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

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

1 *Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that a gain of $19 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 33 months as at March 31, 2017.

Fair Value Derivatives

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

Non-Qualifying Derivatives

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

	Three months ended March 31,	
	2017	2016
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**273**	1,016
Interest rate contracts[2]	**(18)**	4
Commodity contracts[3]	**163**	(184)
Other contracts[4]	**-**	6
Total unrealized derivative fair value gain/(loss), net	**418**	842

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

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

3 Reported within Transportation and other services revenues (2017 - $22 million loss; 2016 - $39 million gain), Commodity sales (2017 - $187 million gain; 2016 - $285 million loss), Commodity costs (2017 - $5 million gain; 2016 - $76 million gain) and Operating and administrative expense (2017 - $7 million loss; 2016 - 14 million loss) in the Consolidated Statements of Earnings.

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

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintains substantial capacity under its committed bank lines of credit to address any contingencies. The Company’s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company also maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is deemed to be in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2017. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

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

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

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

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

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

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

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

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

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

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

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

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

March 31, 2017	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	20	Forward gas price	3.07	4.91	3.62	\$/mmbtu[3]
NGL	(10)	Forward NGL price	0.31	1.53	1.13	\$/gallon
Power	(145)	Forward power price	18.50	63.70	42.61	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(41)	Forward gas price	2.62	7.34	3.29	\$/mmbtu[3]
Crude	46	Forward crude price	40.97	75.64	33.34	\$/barrel
NGL	6	Forward NGL price	0.30	1.72	1.05	\$/gallon
Commodity options[2]						
Crude, NGL	-	Option volatility	22%	100%	49%	
Power	1	Option volatility	23%	50%	24%	
	(123)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 Commodity options contracts are valued using an option model valuation technique.
3 One million British thermal units (mmbtu).

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

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

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

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at March 31, 2017 or 2016.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $110 million as at March 31, 2017 (December 31, 2016 - $110 million).

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

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

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

NET INVESTMENT HEDGES

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

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

11. INCOME TAXES

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

12. RETIREMENT AND POSTRETIREMENT BENEFITS

NET BENEFIT COSTS RECOGNIZED

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

1 Included in net benefit costs for the three months ended March 31, 2017 are costs related to OPEB of $5 million (2016 - $4 million).

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

ACQUIRED PENSION PLANS

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

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

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

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

OTHER POSTRETIREMENT BENEFITS

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

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

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

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

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

MEDICAL COST TRENDS

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans	5%	5%	
United States Plan	7.5%	4.5%	2037

PLAN ASSETS

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

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

Expected Rate of Return on Plan Assets

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

Target Mix for Plan Assets

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

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at February 27, 2017, the pension assets were invested 48.9% in equity securities, 46.7% in fixed income securities and 4.4% in other. The OPEB assets were invested 38.8% in equity securities, 47.6% in fixed income securities and 13.6% in other.

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

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.

PLAN CONTRIBUTIONS BY THE COMPANY

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

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

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

13. SEVERANCE COSTS

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

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

14. RELATED PARTY TRANSACTIONS

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

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

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

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

15. CONTINGENCIES

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

Line 6B Crude Oil Release

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

As at March 31, 2017, EEP's total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge) including those costs that were considered probable and that could be reasonably estimated at March 31, 2017. Despite the efforts EEP has made to ensure the reasonableness of its estimate, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP has completed the cleanup, remediation and restoration of the areas affected by the release. The total estimated cost for the Line 6A crude oil release was approximately US$53 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at March 31, 2017, EEP has no remaining estimated liability.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. As at December 31, 2016, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million applicable limit. Of the remaining US$103 million coverage limit, US$85 million was the subject matter of a lawsuit against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. On May 2, 2017 the arbitration panel issued a decision that was not favourable to Enbridge. As a result, EEP is unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

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

Line 6A and 6B Fines and Penalties

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

Consent Decree

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

TAX MATTERS

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

OTHER LITIGATION

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

16. SUBSEQUENT EVENTS

UNITED STATES SPONSORED VEHICLE STRATEGY

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

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

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

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

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

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