ENBRIDGE INC
Form 6-K
May 12, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

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

the Securities Exchange Act of 1934

Dated May 12, 2016

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

200, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

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

Form 20-F	Form 40-F	P

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

Yes	No	P

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

Yes	No	P

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 33-77022) AND FORM F-10 (FILE NO. 333-198566) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Interim Report to Shareholders for the three months ended March 31, 2016.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date: May 12, 2016

By: /s/ Tyler W. Robinson
Tyler W. Robinson

Vice President & Corporate Secretary

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

March 31, 2016

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2016

This Management s Discussion and Analysis (MD&A) dated May 12, 2016 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, 2016, 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 audited amended consolidated financial statements and MD&A for the year ended December 31, 2015 and filed on May 12, 2016. 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.

Effective January 1, 2016, Enbridge revised its reportable segments to better reflect the underlying operations of the Company. The Company believes this new format more clearly describes the financial performance of its business segments, provides increased transparency with respect to operational results and aligns with business segment decision making and management.

Revisions to the segmented information presentation on a retrospective basis include:

- The replacement of the previous segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate with new segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services;
- Presenting the Earnings before interest and income taxes (EBIT) of each segment as opposed to Earnings attributable to Enbridge Inc. common shareholders. Amounts related to Interest expense, Income taxes, Earnings attributable to noncontrolling interests and redeemable noncontrolling interests and Preference share dividends are now reported on a consolidated basis.

These changes had no impact on reported consolidated earnings for the comparative three-month period ended March 31, 2015.

The Company s activities are carried out through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Mid-Continent and Gulf Coast, Southern Lights Pipeline, Bakken System and Feeder Pipelines and Other.

GAS DISTRIBUTION

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

GAS PIPELINES AND PROCESSING

Gas Pipelines and Processing consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include the Company s interests in the Alliance Pipeline, the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company s interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline, Canadian

Midstream assets located in northeast British Columbia and northwest Alberta and United States Midstream assets located primarily in Texas and Oklahoma.

GREEN POWER AND TRANSMISSION

Green Power and Transmission consists of the Company s investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas and Indiana.

ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company s volume commitments on Alliance Pipeline, Vector and other pipeline systems.

ELIMINATIONS AND OTHER

In addition, Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and elimination of transactions between segments required to present financial performance and financial position on a consolidated basis.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**1,612**	(145)
Gas Distribution	**239**	239
Gas Pipelines and Processing	**61**	36
Green Power and Transmission	**49**	59
Energy Services	**(6)**	(3)
Eliminations and Other	**221**	(441)
Earnings/(loss) before interest and income taxes	**2,176**	(255)
Interest expense	**(412)**	(251)
Income taxes recovery/(expense)	**(417)**	285
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(61)**	(90)
Preference share dividends	**(73)**	(72)
Earnings/(loss) attributable to common shareholders	**1,213**	(383)
Earnings/(loss) per common share	**1.38**	(0.46)
Diluted earnings/(loss) per common share	**1.38**	(0.46)

EARNINGS/(LOSS) BEFORE INTEREST AND INCOME TAXES

For the three months ended March 31, 2016, EBIT was $2,176 million compared with a loss before interest and income taxes of $255 million for the three months ended March 31, 2015. As discussed below in *Adjusted EBIT*, the Company has continued to deliver strong earnings growth from a majority of its businesses. However, the positive impact of this growth and the comparability of the Company s earnings are 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, 2016, the Company s EBIT reflected a $932 million unrealized derivative fair value gain compared with $1,408 million of unrealized derivative fair value loss in the corresponding 2015 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.

EARNINGS/(LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $1,213 million for the three months ended March 31, 2016, or earnings of $1.38 per common share, compared with a loss of $383 million, or loss of $0.46 per common share, for the three months ended March 31, 2015. As discussed below in *Adjusted Earnings*, the comparability of Earnings/(Loss) Attributable to Common Shareholders is impacted by period-over-period variation in interest and income tax expenses, as well as the variation in earnings attributable to noncontrolling interests and redeemable noncontrolling interests. Also impacting the comparability of the Company s period-over-period operating results was an out-of-period adjustment of $71 million recognized in the first quarter of 2015 in respect of an overstatement of deferred income taxes expense in 2013 and 2014.

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 , l 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 available cash flow from operations (ACFFO); expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; expected equity funding requirements for the Company s commercially secured growth program; estimated future dividends; 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 transfer of Enbridge s Canadian Liquids Pipelines business and certain Canadian renewable energy assets to Enbridge Income Partners LP in which the Fund has an indirect interest (the Canadian Restructuring Plan), dividend payout policy and dividend payout expectation; and strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy.

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, 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; impact of the Canadian Restructuring Plan and 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 expected future ACFFO; 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 expected EBIT, adjusted EBIT, earnings/(loss), adjusted earnings/(loss) and associated per share amounts,

3

ACFFO or estimated future dividends. The most relevant assumptions associated with forward-looking statements on 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 and regulatory approvals on construction and in-service schedules.

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

NON-GAAP MEASURES

This MD&A contains references to adjusted EBIT, adjusted earnings/(loss) and ACFFO. Adjusted EBIT represents EBIT adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. Adjusted earnings/(loss) 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.

ACFFO is defined as cash flow provided by operating activities before changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to noncontrolling interests and redeemable noncontrolling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, non-recurring or non-operating factors.

Management believes the presentation of adjusted EBIT, adjusted earnings/(loss) and ACFFO provide 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/(loss) to set targets and to assess the performance of the Company. Management also uses ACFFO to assess the performance of the Company and to set its dividend payout target. Adjusted EBIT, adjusted EBIT for each segment, adjusted earnings/(loss) and ACFFO 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.

4

NON-GAAP RECONCILIATION EBIT TO ADJUSTED EARNINGS

	Three months ended March 31,	
(millions of Canadian dollars)	**2016**	2015
Earnings/(loss) before interest and income taxes	**2,176**	(255)
Adjusting items[1]:		
Changes in unrealized derivative fair value (gains)/loss[2]	**(932)**	1,408
Unrealized intercompany foreign exchange (gains)/loss	**60**	(71)
Hydrostatic testing	**(12)**	-
Make-up rights adjustments	**67**	2
Leak remediation costs, net of leak insurance recoveries	**15**	(12)
Warmer/(colder) than normal weather	**17**	(45)
Project development and transaction costs	**-**	3
Other	**(17)**	1
Adjusted earnings before interest and income taxes	**1,374**	1,031
Interest expense	**(412)**	(251)
Income taxes recovery/(expense)	**(417)**	285
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(61)**	(90)
Preference share dividends	**(73)**	(72)
Adjusting items in respect of:		
Interest expense	**18**	(42)
Income taxes	**241**	(399)
Noncontrolling interests and redeemable noncontrolling interests	**(7)**	6
Adjusted earnings	**663**	468

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.

NON-GAAP RECONCILIATION ADJUSTED EBIT TO ADJUSTED EARNINGS

	Three months ended March 31,	
(millions of Canadian dollars, except per share amounts)	**2016**	2015
Liquids Pipelines	**1,084**	731
Gas Distribution	**240**	198
Gas Pipelines and Processing	**87**	90
Green Power and Transmission	**48**	57
Energy Services	**1**	28
Eliminations and Other	**(86)**	(73)
Adjusted earnings before interest and income taxes	**1,374**	1,031
Interest expense[1]	**(394)**	(293)
Income taxes[1]	**(176)**	(114)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(68)**	(84)
Preference share dividends	**(73)**	(72)
Adjusted earnings	**663**	468

Adjusted earnings per common share	**0.76**	0.56

1 *These balances are presented net of adjusting items.*

Adjusted EBIT

For the three months ended March 31, 2016, adjusted EBIT was $1,374 million, an increase of $343 million over the comparable period in 2015. Growth in consolidated adjusted EBIT was largely driven by stronger contributions from the Liquids Pipelines segment which benefitted from a number of new assets that were placed into service in 2015, the most prominent being the expansion of the Company s mainline system in the third quarter of 2015, as well as the reversal and expansion of Line 9B and completion of the Southern Access Extension Project (Southern Access Extension) in the fourth quarter of 2015, which have provided access to the Eastern Canada and Patoka markets, respectively. The Canadian Mainline contribution increased primarily due to higher throughput that resulted from strong oil sands production in western Canada combined with contributions from the new assets placed into service in 2015, as well as a higher quarter-over-quarter average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll. The Lakehead System also experienced quarter-over-quarter growth in adjusted EBIT, mainly due to higher throughput and contributions from new assets placed into service in 2015. In the first quarter of 2016, the Company also benefitted from stronger adjusted EBIT contributions from the United States Mid-Continent and Gulf Coast, mainly attributed to increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes on Flanagan South Pipeline (Flanagan South) and higher tariffs on Flanagan South and Seaway Pipeline.

Within the Gas Distribution segment, EGD generated higher adjusted EBIT in the first quarter of 2016 compared with the corresponding 2015 period, primarily attributable to higher distribution charges arising from growth in its rate base and the impact of operating under interim rates for the first three months of 2015, and lower storage and transportation costs.

The Gas Pipelines and Processing segment benefitted from strong contributions from Alliance Pipeline under its new services framework that came into effect in the fourth quarter of 2015, and from higher throughput on certain Enbridge Offshore Pipelines (Offshore). However, these positive effects were offset by weaker contributions from Aux Sable due to lower fractionation margins, and lower volumes on US Midstream pipelines due to reduced drilling by producers.

The Green Power and Transmission segment s adjusted EBIT was lower as a result of disruptions at certain eastern Canadian wind farms due to winter weather conditions which caused icing of wind turbines, as well as weaker wind and solar resources at certain facilities.

Adjusted EBIT from Energy Services decreased when compared with the first quarter of 2015 as lower oil prices compressed crude oil location and quality differentials and lower seasonal volatility of natural gas prices resulted in fewer arbitrage opportunities and weaker margin revenue through which to recover demand charges on certain facilities where the Company holds committed transportation capacity.

Adjusted Earnings

Adjusted earnings were $663 million, or $0.76 per common share, for the three months ended March 31, 2016 compared with $468 million, or $0.56 per common share, for the three months ended March 31, 2015.

Partially offsetting the quarter-over-quarter adjusted EBIT growth discussed above was higher interest expense resulting from the incurrence of incremental debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing. The amount of interest capitalized period-over-period also decreased as a result of projects coming into service.

Income taxes increased in the first quarter of 2016 largely due to the quarter-over-quarter increase in earnings.

The above noted negative impacts were offset slightly by a decrease in the adjusted earnings attributable to noncontrolling interests in Enbridge Energy Partners, L.P. (EEP). Although EEP reflected higher quarter-over-quarter contributions from its liquids pipelines businesses, there was a decrease in EEP s overall quarter-over-quarter contribution to adjusted earnings primarily due to higher interest expense.

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

NON-GAAP RECONCILIATION   ADJUSTED EBIT TO ACFFO

To facilitate understanding of the relationship between adjusted EBIT and ACFFO, the following table provides a reconciliation of these two key non-GAAP measures.

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Adjusted earnings before interest and income taxes	**1,374**	1,031
Depreciation and amortization1	**559**	474
Maintenance capital2	**(151)**	(152)
	1,782	1,353
Interest expense3	**(394)**	(293)
Current income taxes3	**(47)**	(26)
Preference share dividends	**(73)**	(71)
Distributions to noncontrolling interests	**(184)**	(158)
Distributions to redeemable noncontrolling interests	**(42)**	(27)
Cash distributions in excess of/(less than) equity earnings3	**(22)**	46
Other non-cash adjustments	**94**	(22)
Available cash flow from operations (ACFFO)	**1,114**	802
1 Depreciation and amortization:		
Liquids Pipelines	***346***	*280*
Gas Distribution	***80***	*77*
Gas Pipelines and Processing	***74***	*65*
Green Power and Transmission	***48***	*46*
Eliminations and Other	***11***	*6*
	559	*474*
2 Maintenance capital:		
Liquids Pipelines	***(43)***	*(62)*
Gas Distribution	***(81)***	*(63)*
Gas Pipelines and Processing	***(11)***	*(7)*
Green Power and Transmission	***(1)***	*-*
Eliminations and Other	***(15)***	*(20)*
	(151)	*(152)*

3 These balances are presented net of adjusting items.

Available Cash Flow from Operations

ACFFO was $1,114 million for the three months ended March 31, 2016 compared with $802 million for the three months ended March 31, 2015. The Company experienced strong quarter-over-quarter growth in ACFFO which was driven by the same factors as discussed in *Adjusted EBIT* above.

Maintenance capital expenditures were comparable period-over-period as higher expenditure in the Company s Gas Distribution and Gas Pipelines and Processing segments were offset by lower maintenance capital expenditures in the Liquids Pipelines segment which reflected a shift in the timing of maintenance activity within the year. Maintenance capital expenditures across all business segments are expected to be higher over the full 2016 year as the Company continues to invest in its maintenance capital program to support the safety and reliability of its operations.

Partially offsetting the quarter-over-quarter increase in ACFFO was higher interest expense as discussed in *Adjusted Earnings* above.

The increase in ACFFO was also partially offset by increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in Enbridge Income Fund (the Fund). Distributions were higher in the first quarter of 2016 compared with the first quarter of 2015 mainly as a result of increased public ownership and distributions per unit in EEP and the Fund.

The ACFFO also includes cash distributions from the Company s equity investments. Cash distributions in the first quarter of 2016 were $186 million compared with $179 million of cash distributions received in the first quarter of 2015. Although the cash distributions period-over-period slightly increased, earnings from such investments in the first quarter of 2016 were much higher compared with the corresponding 2015 period.

NON-GAAP RECONCILIATION ACFFO

The following table provides a reconciliation of cash provided by operating activities (a GAAP measure) to ACFFO.

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Cash provided by operating activities - continuing operations	**1,861**	1,521
Adjusted for changes in operating assets and liabilities[1]	**(122)**	(147)
	1,739	1,374
Distributions to noncontrolling interests	**(184)**	(158)
Distributions to redeemable noncontrolling interests	**(42)**	(27)
Preference share dividends	**(73)**	(71)
Maintenance capital expenditures[2]	**(151)**	(152)
Significant adjusting items:		
Weather normalization	**13**	(33)
Project development and transaction costs	**-**	2
Realized inventory revaluation allowance[3]	**(268)**	(133)
Other items	**80**	-
Available cash flow from operations (ACFFO)	**1,114**	802

1 Changes in operating assets and liabilities include changes in environmental liabilities, net of recoveries.

2 Maintenance capital expenditures are expenditures that are required for the ongoing support and maintenance of the existing pipeline system or that are necessary to maintain the service capability of the existing assets (including the replacement of components that are worn, obsolete or completing their useful lives). For the purpose of ACFFO, maintenance capital excludes expenditures that extend asset useful lives, increase capacities from existing levels or reduce costs to enhance revenues or provide enhancements to the service capability of the existing assets.

3 Realized inventory revaluation allowance relates to losses on sale of previously written down inventory for which there is an approximate offsetting realized derivative gain in ACFFO.

RECENT DEVELOPMENTS

COMMON SHARE ISSUANCES

On March 1, 2016, the Company completed the issuance of 56.5 million common shares at a price of $40.70 per share for gross proceeds of approximately $2.3 billion. The proceeds are being used to reduce short-term indebtedness pending reinvestment in capital projects and are expected to be sufficient to fulfill equity funding requirements for Enbridge s current commercially secured growth program through the end of 2017.

On April 20, 2016, the Company s affiliate Enbridge Income Fund Holdings Inc. (ENF) completed a public equity offering of 20.4 million common shares at a price of $28.25 per share (the Offering Price) for gross proceeds of $575 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.1 million common shares at a price of $28.25 per share, for total proceeds of $143 million, on a private placement basis to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the sale of the common shares to subscribe for additional ordinary trust units of the Fund (Fund Units) at the Offering Price. The proceeds from the issuance of the Fund Units are being used to repay short-term indebtedness pending investment in the secured growth capital programs of Enbridge Pipelines (Athabasca) Inc. and Enbridge Pipelines Inc. (EPI). Upon closing of the transaction, Enbridge s total economic interest in the Fund Group (comprising the Fund, Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and its subsidiaries and investees), through its ownership of ENF, decreased from 89.3% as at March 31, 2016 to 86.9%.

UNITED STATES SPONSORED VEHICLE STRATEGY

On May 2, 2016, EEP announced that it is evaluating opportunities to strengthen its business in light of the current commodity price environment which is particularly impacting the performance of its natural gas gathering and processing assets. As part of this evaluation, EEP is exploring strategic alternatives for its investments in Midcoast Operating Partners, L.P. and Midcoast Energy Partners, L.P. (MEP). These various strategic alternatives may include, but are not necessarily limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures. The evaluation process is in its initial stage and is ongoing, and no decision on any particular strategic alternative has been reached by EEP.

Enbridge has a large inventory of United States liquid pipeline assets which would be well suited to EEP, and Enbridge has previously indicated that it would from time to time consider drop down opportunities to EEP of these assets. However, in light of current market conditions, and their effect on EEP s financing capacity, it is unlikely that any such drop down transactions will be pursued in the near term.

LIQUIDS PIPELINES

Wildfires in Northeastern Alberta

During the first week of May 2016, extreme wildfires in northeastern Alberta resulted in the shutdown of a number of oil sands production facilities and the evacuation of approximately 88,000 people from the city of Fort McMurray which serves as a commercial and regional logistics centre for the oil sands region and a home to a significant portion of the oil sands workforce.

Enbridge s facilities in the region were largely unaffected, however, as a precautionary measure on May 4, 2016, the Company shut down and evacuated its Cheecham terminal and curtailed operations at its Athabasca terminal. It also isolated and shut down pipelines in and out of the Cheecham terminal and shut down or curtailed operations on other pipelines it operates in the region.

With the risk to people and facilities abating, the Company is coordinating with emergency response, public safety and utility officials to restore power and make any necessary repairs to its systems while working closely with producers in the region to restart and return its regional pipeline systems to full operation. The time required to return to full operation will be dependent on a number of factors including the ability to readily access facilities and re-establish power supply while firefighting and emergency response efforts continue in the region.

It is estimated that since the shutdown of Enbridge s facilities, deliveries from the Company s regional oil sands pipelines have been reduced by approximately 900,000 barrels per day. Management currently expects that system capacity will be restored over the next few days subject to ongoing access to facilities. Given the evolving nature of the situation, the impact of the wildfires on the financial performance of the Company cannot be accurately estimated at this time. However, the disruption of service on the regional oil sands pipeline system and corresponding impacts on Enbridge s downstream pipelines, under a variety of restart scenarios, is not expected to significantly impact the Company s financial performance in 2016.

Lakehead System Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

As at March 31, 2016, EEP s total cost estimate for the Line 6B crude oil release is US$1.2 billion ($195 million after-tax attributable to Enbridge). As at March 31, 2016, the liability increased by US$15 million, as compared to December 31, 2015, due to an increase in estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated as at March 31, 2016. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP s remediation spending through March 31, 2016, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under prior or existing insurance policies. As at March 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 aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of US$145 million of coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP s claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was predicated on the outcome of the recovery from that insurer. EEP received a partial recovery of US$42 million from the other remaining insurers and amended its lawsuit such that it included only one insurer.

Of the remaining US$103 million coverage limit, US$85 million was the subject matter of a lawsuit Enbridge filed against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. The recovery of the remaining US$18 million is awaiting resolution of that arbitration. While EEP believes that those costs are eligible for recovery, there can be no assurance that EEP will prevail in the arbitration.

Enbridge has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2016 through April 30, 2017 with a liability program aggregate limit of US$900 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Four 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 the Company s results of operations or financial condition.

As at March 31, 2016, included in EEP s total estimated costs related to the Line 6B crude oil release is US$63 million in fines and penalties. Of this amount, US$55 million related to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$55 million represents EEP s estimate of the amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures could be material. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. In relation to the original market-based rate application, the Federal Energy Regulatory Commission (FERC) issued its decision rejecting Seaway Pipeline s application for market-based rates in February 2014. In that decision, the FERC also announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market-based rate application consistent with the new policy. In December 2014, Seaway Pipeline filed a new market-based rates application. 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 September 17, 2015, the FERC issued its decision setting the application for hearing. The case has been assigned to an Administrative Law Judge (ALJ). The oral hearing with respect to the application will start on July 7, 2016. The ALJ will then issue its initial decision on the application by December 1, 2016. The ALJ s initial decision will then be considered by the FERC Commissioners, who can accept or reject the initial decision in full or in part. It is unclear when the FERC Commissioners decision with respect to market based rates will be received as there is no timing requirement applicable to it.

10

Additionally, in a February 1, 2016 order, the FERC upheld Seaway Pipeline s current committed rates structure and reversed a prior ALJ decision reducing those rates to cost-based levels. With respect to the uncommitted rates, the FERC permitted Seaway Pipeline to include the full Enbridge purchase price (including goodwill) in rate base. FERC s other cost-of-service rulings regarding the uncommitted rates were also largely favourable to Seaway Pipeline. A compliance filing calculating revised rates was filed on March 17, 2016.

GAS DISTRIBUTION

Enbridge Gas New Brunswick Inc. Regulatory Matters

In February 2016, a trial of the action initiated on February 4, 2014 by Enbridge Gas New Brunswick Inc. (EGNB) against the Government of New Brunswick was heard by the New Brunswick courts. There has been no decision yet issued on the matter. The action seeks damages for improper extinguishment of a deferred regulatory asset that was eliminated from EGNB s Consolidated Statements of Financial Position in 2012, due to legislative and regulatory changes enacted by the Government of New Brunswick in that year.

There is no assurance that this or any other action presently maintained by EGNB against the Province of New Brunswick will be successful or will result in any recovery.

GROWTH PROJECTS COMMERCIALLY SECURED PROJECTS

The following table summarizes the current status of the Company s commercially secured projects, organized by business segment.

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1.	Eastern Access (EEP) 3	US$0.3 billion	US$0.2 billion	2016	Under construction
2.	JACOS Hangingstone Project (the Fund Group)	$0.2 billion	$0.1 billion	2016	Under construction
3.	Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$1.8 billion	2017	Under construction
4.	Norlite Pipeline System (the Fund Group)4	$1.3 billion	$0.5 billion	2017	Under construction
5.	Lakehead System Mainline Expansion (EEP)3	US$0.8 billion	US$0.6 billion	2016-2019 (in phases)	Under construction
6.	Canadian Line 3 Replacement Program (the Fund Group)	$4.9 billion	$1.1 billion	2019	Pre-construction
7.		US$2.6 billion	US$0.4 billion	2019	

	U.S. Line 3 Replacement Program (EEP)				Pre-construction
8.	Sandpiper Project (EEP)5	US$2.6 billion	US$0.8 billion	2019	Pre-construction
GAS DISTRIBUTION					
9.	Greater Toronto Area Project	$0.9 billion	$0.8 billion	2016	Complete
GAS PIPELINES AND PROCESSING					
10.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-TBD (in phases)	Complete
11.	Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	TBD	Complete

11

		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
12.	Eaglebine Gathering (EEP)	US$0.2 billion	US$0.1 billion	2015-TBD (in phases)	Complete (Phase 1)
13.	Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Complete
14.	Tupper Main and Tupper West Gas Plants[6]	$0.5 billion	$0.1 billion	2016	Acquisition completed
15.	Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Under construction
16.	Stampede Oil Pipeline	US$0.2 billion	US$0.1 billion	2018	Under construction
GREEN POWER AND TRANSMISSION					
17.	New Creek Wind Project	US$0.2 billion	No significant expenditures to date	2016	Under construction
18.	Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.2 billion (£0.10 billion)	2018	Under 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, 2016.

3 The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.

4 Enbridge will construct and operate the Norlite Pipeline System (Norlite). Keyera Corp. will fund 30% of the project.

5 The Company will construct and operate the Sandpiper Project (Sandpiper). Marathon Petroleum Corporation will fund 37.5% of the project.

6 A deposit of approximately $0.1 billion was made in the first quarter of 2016, with the remaining purchase price payment of approximately $0.4 billion upon closing of the transaction in April 2016.

The description of each of the above projects is provided in the Company s 2015 annual MD&A. Any significant updates since February 19, 2016, the date of the original filing of the Company s MD&A for the year ended December 31, 2015, are discussed below.

LIQUIDS PIPELINES

Eastern Access (EEP)

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. The majority of the Canadian and United States components of Eastern Access initiative were completed between 2013 and 2015. The remaining component of the Eastern Access initiative is the further upsizing of EEP s Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan will increase capacity from 500,000 barrels per day (bpd) to 570,000 bpd and will include pump station modifications at the Griffith, Niles and

Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. This expansion is expected to be placed into service in mid-2016 at an estimated cost of approximately US$0.3 billion, with expenditures to date of approximately US$0.2 billion.

The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to Enbridge Energy, Limited Partnership (EELP) for its interests in the Eastern Access projects until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Eastern Access projects. In return, Enbridge s capital funding contribution requirements to the Eastern Access projects will be netted against its foregone cash distribution.

Norlite Pipeline System (the Fund Group)

The Company is undertaking the development of Norlite, a new industry diluent pipeline originating from Edmonton, Alberta to meet the needs of multiple producers in the Athabasca oil sands region. Based on current engineering design, the project is now expected to provide an initial capacity of approximately

12

218,000 bpd of diluent, with the potential to be further expanded to approximately 465,000 bpd of capacity.

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 to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and 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 Alberta Clipper expansion remains subject to an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd. The timing of receipt of the amendment to the Presidential border crossing permit to allow for increased flow on Alberta Clipper across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

The remaining scope of the Lakehead System Mainline Expansion includes the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois. The Southern Access expansion requires only the addition of pumping horsepower with no pipeline construction. By October of 2015, 950,000 bpd of the capacity expansion was completed in phases and placed in service at a cost of approximately US$0.5 billion. Additional tankage is expected to cost approximately US$0.4 billion with various completion dates that began in the third quarter of 2015 and are expected to continue through the third quarter of 2016. In conjunction with shippers, a decision was made to delay the in-service date of the remaining expansion phase to increase the pipeline capacity to 1,200,000 bpd to align more closely with the anticipated in-service date for the United States portion of the Line 3 Replacement Program (U.S. L3R Program) and Sandpiper. This phase of the project is expected to cost US$0.4 billion.

The remaining components of Southern Access expansion are expected to cost approximately US$0.8 billion, with expenditures incurred to date of approximately US$0.6 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. EEP has the option to increase its economic interest held by up to an additional 15% at cost. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to EELP for its interests in the Lakehead System Mainline Expansion until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Lakehead System Mainline Expansion. In return, Enbridge s capital funding contribution requirements to the Lakehead System Mainline Expansion will be netted against its foregone cash distribution.

Line 3 Replacement Program

In 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the Line 3 Replacement Program (L3R Program). The L3R Program includes the Canadian portion of the L3R Program (Canadian L3R Program) and the U.S. L3R Program.

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) issued final conditions and a recommendation to the Federal Cabinet (the Cabinet) to issue a Certificate of Public Convenience and Necessity for the construction and operation of the pipeline and related facilities. The NEB found that the Canadian L3R Program is in the Canadian public interest. A decision by the Cabinet was expected to be issued three months following the NEB recommendation per guidelines; however, because of the Federal Government s January 27, 2016 announcement that, outside of the NEB process for industry projects, it has directed Federal agencies to conduct assessments of direct and upstream greenhouse gas (GHG)

13

emissions and incremental consultation with affected communities and Indigenous peoples, the Minister of Natural Resources intends to seek an extension of four months to the Government s legislated decision-making time limit (to seven months in total). As a result, Enbridge expects a decision from the Cabinet by the end of November 2016.

Also in April 2016, Environment and Climate Change Canada published a draft review of related upstream GHG emissions estimates for Enbridge s Canadian L3R Program and opened a 30 day public comment period on the draft. The draft review estimates that the upstream GHG emissions in Canada associated with the production and processing of crude oil transported by the Canadian L3R Program, based on a capacity of 760,000 bpd, could be between 19 and 26 megatonnes of carbon dioxide equivalent per year. The draft also found that the estimated emissions are not necessarily incremental; the degree to which the estimated emissions would be incremental depends on the expected price of oil, the availability and costs of other transportation modes, such as crude by rail, and whether other pipeline projects are built. Once the public comment period has closed and the report is finalized, it will be provided to the Cabinet for consideration.

Enbridge reached a settlement agreement with landowner associations representing Line 3 landowners in Canada and as a result these parties withdrew from the hearing process and have expressed their support for the project. The NEB found these agreements to be a persuasive factor in favour of the reasonableness of Enbridge s decommissioning plan.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in early 2019 at an estimated capital cost of approximately $4.9 billion, with expenditures to date of approximately $1.1 billion. With a delay in construction, the cost of this project is expected to increase. The Company continues to review the estimated cost of this project. 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 is in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need and an approval of the pipeline s route (Route Permit) from the Minnesota Public Utilities Commission (MNPUC). The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete and sent the Certificate of Need application to the ALJ for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Court of Appeals decision with respect to EEP s Sandpiper pipeline project discussed below, the ALJ requested direction on how to proceed with the Certificate of Need process for Line 3. On February 1, 2016, the MNPUC issued a written order (the U.S. L3R Order) joining the Line 3 Certificate of Need and Route Permit dockets, requiring the Department of Commerce to prepare an Environmental Impact Statement (EIS) before Certificate of Need and Route Permit processes commence and sent the cases to the Office of Administrative Hearings with direction to re-start the process. On February 5, 2016, EEP filed a Petition for Reconsideration of the requirement to provide an EIS ahead of the commencement of the Certificate of Need and Route Permit proceedings noted in the U.S. L3R Order. At a hearing held on March 24, 2016, the MNPUC denied the Petition for Reconsideration. With the issuance of the Environmental Assessment

Worksheet (EAW) on April 11, 2016, the MNPUC has commenced the EIS process. Consultation regarding the EAW, which defines the scope of the EIS, commenced with a series of public meetings in communities in Minnesota on April 25, 2016 which will conclude on May 13, 2016. The ALJ who is overseeing the Line 3 Certificate of Need and Route Permit processes has ordered a scheduling conference for May 16, 2016 at which the timeline for the Certificate of Need and Route Permit processes will be discussed.

Subject to regulatory and other approvals, the U.S. L3R Program is now expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.4 billion. The Company continues to review the impact of the U.S. L3R Order on the U.S. L3R Program s schedule and cost estimates. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. 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.

Sandpiper Project (EEP)

As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper, which will expand and extend EEP s North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline.

EEP is in the process of obtaining the appropriate permits for constructing Sandpiper in Minnesota. The project requires both a Certificate of Need and Route Permit from the MNPUC. Sandpiper and U.S. L3R Program are being processed independently by the MNPUC; however, because the two projects follow the same route in eastern Minnesota, the MNPUC has required that the agencies prepare the environmental assessment jointly for the two projects before publishing a separate EIS for each project.

On August 3, 2015, the MNPUC issued an order granting a Certificate of Need and a separate order restarting the Route Permit proceedings. On September 14, 2015, the Minnesota Court of Appeals reversed the MNPUC s Certificate of Need order stating that an EIS must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. On January 11, 2016, the MNPUC issued a written order (the Sandpiper Order) re-joining the Certificate of Need and Route Permit process, requiring the Department of Commerce to commence preparation of an EIS, ordering the Office of Administrative Hearings to recommence processing the Certificate of Need and Route Permit applications but to take judicial notice of the record already developed for the Certificate of Need and to require that a final EIS be issued before the Certificate of Need and Route Permit processes commence. On February 1, 2016, EEP filed a Petition for Reconsideration of the requirement to provide an EIS ahead of the commencement of the Certificate of Need and Route Permit noted in the Sandpiper Order. At a hearing held on March 24, 2016, the MNPUC denied the Petition for Reconsideration. With the issuance of the EAW on April 11, 2016, the MNPUC has commenced the EIS process. Consultation regarding the EAW, which defines the scope of the EIS, commenced with a series of public meetings in communities in Minnesota on April 25, 2016 which will conclude on May 13, 2016.

Subject to regulatory and other approvals, Sandpiper is expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.8 billion. The Company continues to review the impact of the Sandpiper Order on the project s schedule and cost estimates.

GAS DISTRIBUTION

Greater Toronto Area (GTA) Project

EGD undertook the expansion of its natural gas distribution system in the GTA to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. The GTA project involved the construction of two new segments of pipeline, a 27-kilometre (17-mile), 42-inch diameter pipeline (Western segment) and a 23-kilometre (14-mile), 36-inch diameter pipeline (Eastern segment) as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in the GTA. Both the Western and Eastern segments were placed into service in

March 2016. The total project cost, which includes installation and upgrade of two additional stations through 2017, is estimated to be approximately $0.9 billion, with expenditures up to March 31, 2016 of approximately $0.8 billion.

GAS PIPELINES AND PROCESSING

Tupper Main and Tupper West Gas Plants

In April 2016, Enbridge completed the acquisition of the Tupper Main and Tupper West gas plants (the Tupper Plants) and associated pipelines from a Canadian subsidiary of Murphy Oil Corporation (Murphy Oil) for a purchase price of approximately $0.5 billion. A deposit of approximately $0.1 billion was made in the first quarter of 2016, with the remaining purchase price payment of approximately $0.4 billion paid upon closing of the transaction in April 2016. The Tupper Plants have a combined total licensed capacity of 320 million cubic feet per day and are located within the Montney gas play, 35-kilometres southwest of Dawson Creek, British Columbia, adjacent to Enbridge s existing Sexsmith gathering system and close to the Alliance Pipeline, which is 50% owned by the Fund Group. These assets, including 53-kilometres of high pressure pipelines, are currently in operation and are underpinned by long-term take-or-pay contracts.

Aux Sable Extraction Plant Expansion

In 2014, the Company approved the expansion of fractionation capacity and related facilities at the Aux Sable extraction and fractionation plant located in Channahon, Illinois. The expansion will serve the growing NGL-rich gas stream on the Alliance Pipeline, allow for effective management of Alliance Pipeline s downstream natural gas heat content and support additional production and sale of NGL products. The expansion is expected to provide approximately 24,500 bpd of incremental fractionation capacity and is now expected to be placed into service in the third quarter of 2016. The Company s share of the project cost is approximately US$0.1 billion.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway Project (Northern Gateway) involves constructing a twin 1,178-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to transport imported condensate from Kitimat to the Edmonton area and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

In June 2014, the Governor in Council approved Northern Gateway, subject to 209 conditions following the recommendation from the Joint Review Panel (JRP). The Company continues to work closely with its customers in advancing this project to open West Coast market access and is making progress in fulfilling the conditions and building relationships and trust with communities and Aboriginal groups along the proposed route. One of the 209 conditions, the sunset clause, also specifies that the Certificates of Public Convenience and Necessity will expire on December 31, 2016, unless construction starts by that date or the NEB otherwise directs. On May 6, 2016, Northern Gateway and the 31 Aboriginal equity partners who are part owners in Northern Gateway requested that the NEB grants a three year extension to the sunset clause, in order to provide time to secure legal and regulatory certainty and to continue consultations with Aboriginal communities.

Nine applications to the Federal Court of Appeal (Federal Court) for leave for judicial review of the Order in Council were filed in July 2014. The applicants made two basic arguments in seeking leave. First, they argued that the JRP report and the Order in Council contain evidentiary gaps or gaps in reasoning. Second, they alleged that the Crown failed to discharge its constitutional duty to consult and, if appropriate, accommodate the Aboriginal applicants.

The Federal Court consolidated the nine applications into one proceeding. The hearing of these applications commenced in Vancouver, British Columbia, on October 1, 2015 and concluded on October 8, 2015. Depending on the outcome of these proceedings, which is anticipated for 2016, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

The Company reviewed an updated cost estimate of Northern Gateway based on full engineering analysis of the pipeline route and terminal location. Based on this comprehensive review, the Company expects that the final cost of the project will be substantially higher than the preliminary cost figures included in the Northern Gateway filing with the JRP, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.6 billion, of which approximately half is being funded by potential shippers on Northern Gateway.

The in-service date of the project will be dependent upon the timing and outcome of judicial reviews, continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities). Of the 48 Aboriginal groups eligible to participate as equity owners, 31 have signed up to do so.

Given the many uncertainties surrounding Northern Gateway, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html and Northern Gateway also maintains a website at www.northerngateway.ca where the full regulatory application submitted to the NEB, the 2010 Enbridge Northern Gateway Community Social Responsibility Report and the December 19, 2013 Report of the JRP on the Northern Gateway Application are available. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the JRP website or the Northern Gateway website is incorporated by reference in, or otherwise part, of this MD&A***.

FINANCIAL RESULTS

LIQUIDS PIPELINES

Earnings before Interest and Income Taxes

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Canadian Mainline	**309**	160
Lakehead System	**353**	274
Regional Oil Sands System	**93**	86
Mid-Continent and Gulf Coast	**181**	84
Southern Lights Pipeline	**41**	36
Bakken System	**54**	61
Feeder Pipelines and Other	**53**	30
Adjusted earnings before interest and income taxes	**1,084**	731
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**568**	(830)
Canadian Mainline - Line 9B costs incurred during reversal	**-**	(1)
Lakehead System - changes in unrealized derivative fair value loss	**(1)**	(3)
Lakehead System - hydrostatic testing	**12**	-
Lakehead System - leak remediation costs	**(20)**	-
Regional Oil Sands System - leak insurance recoveries	**5**	12
Regional Oil Sands System - make-up rights adjustment	**(14)**	6
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value loss	**-**	(1)
Mid-Continent and Gulf Coast - make-up rights adjustment	**(50)**	(10)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**32**	(48)
Bakken System - make-up rights adjustment	**(3)**	3
Bakken System - changes in unrealized derivative fair value loss	**(1)**	(1)
Feeder Pipelines and Other - make-up rights adjustment	**-**	(2)
Feeder Pipelines and Other - project development costs	**-**	(1)
Earnings/(loss) before interest and income taxes	**1,612**	(145)

Additional details on items impacting Liquids Pipelines EBIT include:

- Canadian Mainline EBIT for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage risk exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.

- Lakehead System EBIT for the first quarter of 2016 included recoveries in relation to hydrostatic testing performed on Line 2B in 2015.

- Lakehead System EBIT for the first quarter of 2016 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. Refer to *Recent Developments Liquids Pipelines Lakehead System Line 6B Crude Oil Release.*

- Regional Oil Sands System EBIT for each period included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013.

- Regional Oil Sands System EBIT for each period included make-up rights adjustments to recognize revenue for certain long-term take-or-pay contracts rateably over the contract life. For the purposes of adjusted EBIT, the Company reflects contributions from these contracts rateably over the life of the contract, consistent with contractual cash payments under the contract.

- 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 exposure on United States dollar cash flows from the Southern Lights Class A units.

Canadian Mainline

Canadian Mainline adjusted EBIT increased in the first quarter of 2016 compared with the corresponding 2015 period. Positively impacting adjusted EBIT was higher throughput driven by strong oil sands production combined with contributions from new assets placed into service in 2015, the most prominent being the expansion of the Company s mainline system completed in the third quarter of 2015 and the reversal and expansion of Line 9B completed in the fourth quarter of 2015, as well as new surcharges for certain system expansions, including the Edmonton to Hardisty Expansion that was completed in the second quarter of 2015. Higher throughput on the Canadian Mainline also reflected increased downstream demand in the first quarter of 2016 from the completion of the Southern Access Extension in the fourth quarter of 2015. Adjusted EBIT from Southern Access Extension is reported within Feeder Pipelines and Other.

Other factors contributing to an increase in quarter-over-quarter adjusted EBIT included a higher quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll, changes in which are inversely related to the Lakehead System Toll, as well as the impact of a stronger United States dollar as the IJT Benchmark Toll and its components are set in United States dollars. The majority of the Company s foreign exchange risk on Canadian Mainline revenue is hedged. For the three months ended March 31, 2016, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.11, compared with $1.08 for the corresponding 2015 period. Factors which partially offset the higher quarter-over-quarter Canadian Mainline adjusted EBIT included higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities.

Adjusted EBIT for the balance of the year will reflect a decrease in Canadian Mainline IJT Residual Benchmark Toll from US$1.63 to US$1.46 effective April 1, 2016 and the absence of period-over-period positive variance for new surcharges relating to Edmonton to Hardisty Expansion as they took effect in the second quarter of 2015.

In 2015, the Company commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $12 million and $9 million in revenues were recorded in the first quarter of 2016 and 2015, respectively, but these amounts were offset by a corresponding increase in operating and administrative expense in the respective periods.

Supplemental information related to the Canadian Mainline for the three months ended March 31, 2016 and 2015 is provided below:

March 31,	**2016**	2015
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.07**	$4.02
Lakehead System Local Toll[2]	**$2.44**	$2.49
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.63**	$1.53

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, 2015, the IJT Benchmark Toll increased from US$4.02 to US$4.07.*

2 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2015, the Lakehead System Local Toll decreased from US$2.49 to US$2.39 and effective July 1, 2015, this toll increased to US$2.44. Effective April 1, 2016, this toll increased to US$2.61.*

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, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased from US$1.53 to US$1.63. Effective April 1, 2016, this toll decreased to US$1.46, coinciding with the revised Lakehead System Local Toll.

Throughput Volume

	Three months ended March 31,	
	2016	2015
(thousands of bpd)		
Average throughput volume[1]	**2,543**	2,210

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, 2016 compared with the first quarter of 2015. The quarter-over-quarter increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher average United States to Canadian dollar exchange rate (Exchange Rate) in the first quarter of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$256 million for the three months ended March 31, 2016 compared with US$222 million for the three months ended March 31, 2015. The quarter-over-quarter increase reflected higher throughput, as well as contributions from new assets placed into service in 2015, the most prominent being the expansion of the Company s mainline system completed in the third quarter of 2015. As discussed under *Canadian Mainline* above, higher throughput on the Lakehead System also reflected increased downstream demand resulting from the completion of Southern Access Extension and the reversal and expansion of Line 9B. Partially offsetting the increase in adjusted EBIT were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base.

As noted above, positively impacting Lakehead System quarter-over-quarter adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first quarter of 2016 due to the strengthening United States dollar versus the Canadian dollar. The Exchange Rate was $1.37 for the three months ended March 31, 2016 compared with $1.24 in the comparative period of 2015. 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,	
	2016	2015

(thousands of bpd)		
Average throughput volume1	**2,735**	2,330

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

Mid-Continent and Gulf Coast

Mid-Continent and Gulf Coast adjusted EBIT increased in the first quarter of 2016 compared with the first quarter of 2015. The quarter-over-quarter increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first quarter of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$132 million for the three months ended March 31, 2016 compared with US$67 million for the three months ended March 31, 2015. The increase in adjusted EBIT primarily reflected increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes on Flanagan South and higher tariffs on Flanagan South and Seaway Pipeline. Throughput on Flanagan South is affected by Canadian Mainline apportionment and the upstream apportionment experienced in the first quarter of 2015 was partially alleviated with the expansion of the Company s mainline system completed in the third quarter of 2015.

As noted above, positively impacting quarter-over-quarter adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first quarter of 2016 due to the strengthening United States dollar versus the Canadian dollar. 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*.

Bakken System

Bakken System adjusted EBIT decreased in the first quarter of 2016 compared with the first quarter of 2015. The quarter-over-quarter decrease in adjusted EBIT reflected weaker performance on the United States portion of the Bakken System, partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first quarter of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Bakken System adjusted EBIT was US$37 million for the three months ended March 31, 2016 compared with US$47 million for the corresponding 2015 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 subject to an annual adjustment were decreased effective April 1, 2015. This was partially offset by the effects of higher throughput driven by enhanced downstream capacity on the mainline system and as a result of volumes shifting to pipelines from other higher cost transportation alternatives such as rail.

As noted above, impacting quarter-over-quarter adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first quarter of 2016 due to the strengthening United States dollar versus the Canadian dollar. Similar to Lakehead System, a part of the United States portion of the Bakken System 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*.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted EBIT increased in the first quarter of 2016 compared with the first quarter of 2015, primarily reflecting a full quarter of contributions from Southern Access Extension which was placed into service in the fourth quarter of 2015.

GAS DISTRIBUTION

Earnings before Interest and Income Taxes

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**175**	138
Noverco Inc. (Noverco)	**38**	31
Other Gas Distribution and Storage	**27**	29
Adjusted earnings before interest and income taxes	**240**	198
EGD - (warmer)/colder than normal weather	**(17)**	45
Noverco - changes in unrealized derivative fair value loss	**(1)**	(4)
Noverco - recognition of regulatory balances	**17**	-
Earnings before interest and income taxes	**239**	239

Additional details on items impacting Gas Distribution EBIT include:

- Noverco EBIT for the first quarter of 2016 included the recognition of regulatory assets in relation to employee future benefits.

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,	
	2016	2015
(millions of Canadian dollars)		
Adjusted earnings before interest and income taxes	**175**	138
Interest expense	**(37)**	(38)
Income taxes	**(20)**	(27)
Adjusting items in respect of:		
Income taxes	**(4)**	12
Adjusted earnings	**114**	85
EGD - (warmer)/colder than normal weather	**(13)**	33
Earnings attributable to common shareholders	**101**	118

EGD adjusted earnings increased for the three months ended March 31, 2016 compared with the corresponding 2015 period. The increase primarily resulted from higher distribution charges arising from growth in EGD s rate base and the impact of operating under interim rates for the first three months of 2015, and lower storage and transportation costs. These positive effects were partially offset by lower transactional services revenues, mainly relating to pipeline optimization activities.

Noverco

Noverco adjusted EBIT increased in the first quarter of 2016 compared with the first quarter of 2015. The increase in adjusted EBIT reflected higher operating earnings from Noverco s underlying gas and power distribution investments through Gaz Metro Limited Partnership (Gaz Metro) due to a favourable Exchange Rate on Gaz Metro s United States based business, as well as a higher approved rate base that took effect in the first quarter of 2016.

GAS PIPELINES AND PROCESSING

Earnings before Interest and Income Taxes

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Aux Sable	**(3)**	6
Alliance Pipeline	**49**	40
Vector Pipeline	**9**	9
Canadian Midstream	**21**	21
Enbridge Offshore Pipelines (Offshore)	**13**	2
US Midstream	**2**	17
Other	**(4)**	(5)
Adjusted earnings before interest and income taxes	**87**	90
Alliance Pipeline - changes in unrealized derivative fair value gains/(loss)	**12**	(12)
US Midstream - changes in unrealized derivative fair value loss	**(38)**	(43)
US Midstream - make-up rights adjustment	**-**	1
Earnings before interest and income taxes	**61**	36

Aux Sable

Aux Sable adjusted EBIT decreased for the three months ended March 31, 2016 compared with the corresponding 2015 period, primarily reflecting lower fractionation margins that resulted from continuing weakness in the commodity price environment.

Alliance Pipeline

Alliance Pipeline adjusted EBIT for the three months ended March 31, 2016, which represents EBIT from the Company s 50% equity investment in Alliance Pipeline, increased compared with the first quarter of 2015, primarily due to lower operating costs and higher revenues resulting from strong demand for seasonal firm service under Alliance Pipeline s new services framework that commenced in the fourth quarter of 2015. The increase in adjusted EBIT was partially offset by the absence of non-renewal fees for the United States portion of Alliance Pipeline and higher depreciation expense that had been recovered through tolls in the first quarter of 2015.

Offshore

Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT was US$10 million for the three months ended March 31, 2016 compared with US$2 million for the three months ended March 31, 2015. The increase in Offshore adjusted EBIT primarily reflected contributions from Heidelberg Oil Pipeline which was placed into service in January 2016 and an increase in volumes in the Mississippi Canyon Gas Pipeline. Favourable impact of translating United States dollar earnings at a higher Exchange Rate during the first quarter of 2016 also contributed to higher period-over-period adjusted EBIT.

US Midstream

Excluding the impact of foreign exchange translation to Canadian dollars, US Midstream adjusted EBIT was US$2 million for the three months ended March 31, 2016 compared with US$14 million for the three months ended March 31, 2015. The period-over-period decrease in US Midstream adjusted EBIT reflected lower volumes primarily attributable to the continued low commodity price environment which resulted in reduced drilling by producers. The decrease in adjusted EBIT was partially offset by lower operating costs. As at March 31, 2016, Enbridge s ownership interest in US Midstream, held through EEP, was 19.2% (December 31, 2015 - 19.2%).

GREEN POWER AND TRANSMISSION

Earnings before Interest and Income Taxes

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Green Power and Transmission	**48**	57
Adjusted earnings before interest and income taxes	**48**	57
Green Power and Transmission - changes in unrealized derivative fair value gains	**1**	2
Earnings before interest and income taxes	**49**	59

Green Power and Transmission adjusted EBIT decreased for the three months ended March 31, 2016 compared with the corresponding 2015 period. Green Power and Transmission reflected lower adjusted EBIT in the first quarter of 2016 as a result of disruptions at certain eastern Canadian wind farms due to winter weather conditions which caused icing of wind turbines, as well as weaker wind and solar resources at certain facilities.

ENERGY SERVICES

Earnings before Interest and Income Taxes

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Energy Services	**1**	28
Adjusted earnings before interest and income taxes	**1**	28
Energy Services - changes in unrealized derivative fair value loss	**(7)**	(31)
Loss before interest and income taxes	**(6)**	(3)

Additional details on items impacting Energy Services EBIT include:

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

Energy Services adjusted EBIT decreased in the first quarter of 2016 compared with the first quarter of 2015. Energy Services operations include Canadian and United States components. Within Energy Services adjusted EBIT for the three months ended March 31, 2016 was US$5 million (2015 - US$12 million) from its United States operations.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT decreased when compared with the first quarter of 2015 as low oil prices compressed crude oil location and quality differentials and lower seasonal volatility of natural gas prices resulted in fewer arbitrage opportunities and weaker margin revenue through which to recover demand charges on certain facilities where the Company holds committed transportation capacity. 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,	
	2016	2015
(millions of Canadian dollars)		
Operating and administrative	**(15)**	(17)
Realized foreign exchange derivative loss	**(87)**	(51)
Other	**16**	(5)
Adjusted loss before interest and income taxes	**(86)**	(73)
Changes in unrealized derivative fair value gains/(loss)	**367**	(437)
Unrealized intercompany foreign exchange gains/(loss)	**(60)**	71
Drop down transaction costs	**-**	(2)
Earnings/(loss) before interest and income taxes	**221**	(441)

Included in Eliminations and Other adjusted loss before interest and income taxes for the first quarter of 2016 was a realized loss of $87 million (2015 - $51 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 and ACFFO.

The notional amount of foreign currency derivatives realized during the first quarter of 2016 was US$261 million (2015 - US$238 million) with an average price to sell United States dollars for Canadian dollars at $1.04 (2015 - $1.03). The Exchange Rate for the three months ended March 31, 2016 was $1.37 (2015 - $1.24). As the hedged rate was lower than the Exchange Rate in each of the first quarters of 2016 and 2015, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for the first quarter of 2016 was greater than the comparative 2015 period due to a greater unfavourable spread between the 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 Exchange Rate of $1.37 for the first quarter of 2016 (2015 - $1.24) 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.

Other adjusted EBIT increased in the first quarter of 2016 compared with the corresponding 2015 period and reflected realized foreign exchange gains 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 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 the issuance of debt, 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. Furthermore, the Company targets to maintain sufficient standby liquidity to bridge fund through protracted capital markets disruptions. The Company targets to maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions 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 identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles EEP and the Fund Group.

CAPITAL MARKET ACCESS

The Company and its self-funding subsidiaries ensure ready access to capital markets 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. As discussed under *Financing Activities* below, the Company and ENF have raised $2.3 billion and $0.6 billion, respectively, through public offerings since the beginning of 2016.

Bank Credit and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge maintains ready access to funds through committed bank credit facilities and it actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company s committed credit facilities as at March 31, 2016 and December 31, 2015.

		March 31, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge	2017-2020	**6,866**	**3,643**	**3,223**	6,988
Enbridge (U.S.) Inc.	2017	**4,189**	**1,427**	**2,762**	4,470
EEP	2017-2020	**3,372**	**2,386**	**986**	3,598
EGD	2017-2019	**1,009**	**479**	**530**	1,010
The Fund	2018	**1,500**	**11**	**1,489**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**26**	**-**	**26**	28

EPI	2017	**3,000**	**1,922**	**1,078**	3,000
Enbridge Southern Lights LP	2017	**5**	-	**5**	5
Midcoast Energy Partners, L.P.	2018	**1,051**	**571**	**480**	1,121
Total committed credit facilities		**21,018**	**10,439**	**10,579**	21,720

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

In addition to the committed credit facilities noted above, the Company also has $334 million (December 31, 2015 - $349 million) of uncommitted demand credit facilities, of which $123 million (December 31, 2015 - $185 million) were unutilized as at March 31, 2016.

The Company s net available liquidity of $11,584 million as at March 31, 2016 was inclusive of $1,735 million of unrestricted cash and cash equivalents and net of bank indebtedness of $730 million as reported on the Consolidated Statements of Financial Position.

The Company s credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at March 31, 2016, the Company was in compliance with all debt covenants and expects to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled Enbridge to manage its credit profile. The Company actively monitors and manages key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at March 31, 2016, the Company s debt capitalization ratio was 62.7% compared with 65.5% as at December 31, 2015.

There are no material restrictions on the Company s cash with the exception of cash in trust of $7 million related to cash collateral and 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. 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, 2016, the major contributing factor of which was the funding of the Company s growth capital program. Despite this negative working capital, the Company continues to have significant liquidity available through committed credit facilities, which allow the funding of liabilities as they become due. As discussed above, as at March 31, 2016, the Company s net available liquidity totalled $11,584 million (December 31, 2015 - $10,325 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

OPERATING ACTIVITIES

Cash generated from operating activities was $1,861 million for the three months ended March 31, 2016 compared with $1,521 million for the three months ended March 31, 2015.

The Company s cash flows from operating activities increased by $340 million in the first quarter of 2016, relative to the comparative 2015 period. The cash growth delivered by operations is a reflection of the positive operating factors discussed under *Adjusted EBIT* and *Adjusted Earnings*, which include strong contributions from Liquids Pipelines and Gas Distribution segments, partially offset by higher financing costs resulting from the incurrence of incremental debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing.

Enbridge s operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within Energy Services and Gas Distribution segments, the timing of tax payments, general variations in activity levels within the Company s businesses, as well as timing of cash receipts and payments. During the first quarter of 2016, the change in cash generated from operating activities over the comparable period in 2015 had an unfavourable variance of $26 million due to offsetting reasons. Lower crude oil and natural gas prices during the first quarter of 2016 resulted in lower accounts payable balances in the Energy Services and Gas Distribution businesses. Further contributing to the period-over period unfavourable variance was lower recovery of the regulatory balances in the Gas Distribution business. These unfavourable effects were partially offset by the effects of lower crude oil and natural gas prices which reduced the crude oil inventory and receivable balances in the Energy Services segment and gas inventory balances in the Gas Distribution segment.

INVESTING ACTIVITIES

Cash used in investing activities was $1,852 million for the three months ended March 31, 2016 compared with $1,877 million for the three months ended March 31, 2015. The timing of project approval, construction and in-service dates impacts the timing of cash requirements. The Company continues with the execution of its growth capital program which is further described in *Growth Projects Commercially Secured Projects*. During the first quarter of 2016, additions to property, plant and equipment resulted in cash spending of $1,645 million compared with $1,590 million spent in the first quarter of 2015. This increase in spending was more than offset by a quarter-over-quarter decrease in cash usage on acquisitions. In the first quarter of 2015, the Company spent $106 million on acquisition of a midstream business by EEP, whereas in the first quarter of 2016, the Company paid a deposit of $54 million in connection with the acquisition of Tupper Main and Tupper West gas plants which was completed on April 1, 2016.

FINANCING ACTIVITIES

Net cash generated from financing activities was $751 million for the three months ended March 31, 2016 compared with $225 million for the three months ended March 31, 2015. The increase in the first quarter of 2016 over the comparative 2015 period was mainly due to the issuance of common share offerings. The proceeds from these offerings were partly utilized to reduce the Company s credit facilities and commercial paper draws. The Company s overall debt was decreased by $921 million during the first quarter of 2016 compared with an overall increase of $189 million during the first quarter of 2015.

Financing activities also included transactions between the Company s sponsored vehicles and their public unitholders, which are referred to as noncontrolling interests and redeemable noncontrolling interests in the Company s Consolidated Financial Statements. During the first quarter of 2016, the Company made distributions, net of contributions, of $206 million; whereas in the comparative 2015 period the Company received contributions, net of distributions of $340 million, primarily as a result of equity issuances to the public by the sponsored vehicles.

Finally, the Company increased its common share dividend rate effective March 2016. With the rate increase and the higher common shares outstanding, the amount of dividends paid by the Company during the first three months of 2016 increased compared with the same period in 2015.

Common Share Issuance

On March 1, 2016, the Company completed the issuance of 56.5 million common shares for gross proceeds of approximately $2.3 billion, inclusive of 7.4 million shares issued on exercise of the full amount of the underwriters over-allotment option. The proceeds are being used to reduce short-term indebtedness pending reinvestment in capital projects and are expected to be sufficient to fulfill equity funding requirements for Enbridge s current commercially secured growth program through the end of 2017 before consideration of the additional equity raised by ENF subsequent to the quarter.

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, 2016, dividends declared were $460 million (2015 - $396 million), of which $276 million (2015 - $241 million) were paid in cash and reflected in financing activities. The remaining $184 million (2015 - $155 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, 2016, 40.0% (2015 - 39.1%) of total dividends declared were reinvested.

On April 22, 2016, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2016 to shareholders of record on May 16, 2016.

Common Shares	$0.53000
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

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $2,554 million which are expected to be paid over the next five years.

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. Refer to Enbridge s 2015 annual MD&A for further details on financial instrument risk management.

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

The following table presents the effect of derivative instruments on the Company s consolidated earnings and consolidated comprehensive income.

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(35)**	45
Interest rate contracts	**(576)**	(664)
Commodity contracts	**16**	19
Other contracts	**31**	(8)
Net investment hedges		
Foreign exchange contracts	**84**	(123)
	(480)	(731)
Amount of (gains)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Foreign exchange contracts1	**3**	-
Interest rate contracts2	**(21)**	10
Commodity contracts3	**(8)**	(20)
Other contracts4	**(26)**	5
	(52)	(5)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts2	**26**	(23)
Commodity contracts3	**-**	5
	26	(18)
Amount of unrealized gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts1	**1,016**	(1,293)
Interest rate contracts2	**4**	-
Commodity contracts3	**(184)**	(192)
Other contracts4	**6**	2
	842	(1,483)

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

2 Reported within Interest expense in the Consolidated 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.

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. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. The

Company is in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2016.

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. Credit risk also arises from trade and other long-term receivables. These risks are mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Refer to Enbridge s 2015 annual MD&A for further details on Enbridge s credit risk management.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Classification of Deferred Taxes on the Statements of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations

Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis. The new standard requires that an acquirer must recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria will simplify the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Amendments to the Consolidation Analysis

ASU 2015-02, issued in February 2015, revises the current consolidation guidance which results in a change in the determination of whether an entity consolidates certain types of legal entities. The new standard is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied on a full or modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-02 on a modified retrospective basis, which amended and clarified the guidance on variable interest entities (VIEs). There was a significant change in the assessment of limited partnerships and other similar legal entities as VIEs, including the removal of the presumption that the general partner should consolidate a limited partnership. As a result, the Company has determined that a majority of the limited partnerships that are currently consolidated or equity accounted for are VIEs. The amended guidance did not impact the Company s accounting treatment of such entities, however, material disclosures for VIEs have been provided, as necessary.

QUARTERLY FINANCIAL INFORMATION

	2016	2015				2014		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**8,795**	8,914	8,320	8,631	7,929	8,797	8,297	10,026
Earnings/(loss) attributable to common shareholders	**1,213**	378	(609)	577	(383)	88	(80)	756
Earnings/(loss) per common share	**1.38**	0.44	(0.72)	0.68	(0.46)	0.11	(0.10)	0.92
Diluted earnings/(loss) per common share	**1.38**	0.44	(0.72)	0.67	(0.46)	0.10	(0.10)	0.91
Dividends per common share	**0.530**	0.465	0.465	0.465	0.465	0.350	0.350	0.350
EGD - warmer/(colder) than normal weather	**13**	16	-	6	(33)	(1)	2	(4)
Changes in unrealized derivative fair value (gains)/loss	**(652)**	45	654	(296)	977	164	396	(430)

Several factors impact comparability of the Company s financial results on a quarterly basis, including, but not limited to, 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.

EGD and the Company s other gas distribution businesses are subject to seasonal demand. A significant portion of 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 and other gas distribution businesses 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.

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 weather in EGD s franchise area and changes in unrealized gains and losses outlined above, significant items impacting the consolidated quarterly earnings are noted below:

- Included in earnings is the Company s share of after-tax leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $2 million, $5 million and $12 million were recognized in the first quarter of 2016 and the second and third quarters of 2014, respectively. In the fourth quarter of 2014, the Company recognized an out-of-period adjustment of $5 million to reduce Enbridge s share of leak remediation costs recognized in the third quarter of 2014.

- Included in earnings are after-tax insurance recoveries associated with the Line 37 crude oil release which occurred in June 2013. Insurance recoveries of $3 million were recognized in the first quarter of 2016, $9 million and $13 million recognized in each of the first quarter and fourth quarter of 2015 and $4 million was recognized in each of the second quarter and fourth quarter of 2014, respectively. Earnings also reflected after-tax costs of $6 million in the second quarter of 2015 and $4 million in the third quarter of 2014, in connection with the Line 37 crude oil release.

- 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 Canadian Restructuring Plan, 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.

- Included in the second quarter of 2015 and fourth quarter of 2014 were the tax impact 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 sale of partnership units, the tax consequences have remained in consolidated earnings and resulted in a charge of $39 million and $157 million, respectively.

- Included in earnings were after-tax gains on the disposal of non-core Offshore assets. The Company recognized gains of $4 million in the second quarter of 2015 and $14 million in the fourth quarter of 2014.

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

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	929,112,973
Stock Options - issued and outstanding (24,715,464 vested)	40,695,719

1 *Outstanding share data information is provided as at April 29, 2016.*
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 the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*
3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

March 31, 2016

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2016	2015
(unaudited; millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**4,804**	5,231
Gas distribution sales	**1,007**	1,591
Transportation and other services	**2,984**	1,107
	8,795	7,929
Expenses		
Commodity costs	**4,711**	5,042
Gas distribution costs	**754**	1,364
Operating and administrative	**1,080**	991
Depreciation and amortization	**559**	474
Environmental costs, net of recoveries	**17**	(11)
	7,121	7,860
	1,674	69
Income from equity investments	**226**	133
Other income/(expense)	**276**	(457)
Interest expense	**(412)**	(251)
	1,764	(506)
Income taxes recovery/(expense) *(Note 10)*	**(417)**	285
Earnings/(loss)	**1,347**	(221)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(61)**	(90)
Earnings/(loss) attributable to Enbridge Inc.	**1,286**	(311)
Preference share dividends	**(73)**	(72)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**1,213**	(383)
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 7)*	**1.38**	(0.46)
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 7)*	**1.38**	(0.46)

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2016	2015
(unaudited; millions of Canadian dollars)		
Earnings/(loss)	**1,347**	(221)
Other comprehensive income/(loss), net of tax		
Change in unrealized loss on cash flow hedges	**(443)**	(505)
Change in unrealized gain/(loss) on net investment hedges	**394**	(426)
Other comprehensive income/(loss) from equity investees	**(2)**	9
Reclassification to earnings of realized cash flow hedges	**(10)**	(9)
Reclassification to earnings of unrealized cash flow hedges	**9**	(30)
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**2**	4
Change in foreign currency translation adjustment	**(1,377)**	1,597
Other comprehensive income/(loss)	**(1,427)**	640
Comprehensive income/(loss)	**(80)**	419
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**100**	(125)
Comprehensive income attributable to Enbridge Inc.	**20**	294
Preference share dividends	**(73)**	(72)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(53)**	222

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31,	
	2016	2015
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares		
Balance at beginning and end of period	**6,515**	6,515
Common shares		
Balance at beginning of period	**7,391**	6,669
Common shares issued	**2,241**	-
Dividend reinvestment and share purchase plan	**184**	155
Shares issued on exercise of stock options	**12**	13
Balance at end of period	**9,828**	6,837
Additional paid-in capital		
Balance at beginning of period	**3,301**	2,549
Drop down of interest to Enbridge Energy Partners, L.P.	**-**	218
Stock-based compensation	**22**	16
Options exercised	**(5)**	(5)
Dilution gains/(loss) and other	**(3)**	34
Balance at end of period	**3,315**	2,812
Retained earnings		
Balance at beginning of period	**142**	1,571
Earnings/(loss) attributable to Enbridge Inc.	**1,286**	(311)
Preference share dividends	**(73)**	(72)
Common share dividends declared	**(460)**	(396)
Dividends paid to reciprocal shareholder	**6**	6
Redemption value adjustment attributable to redeemable noncontrolling interests	**(118)**	182
Adjustment relating to equity method investment	**(29)**	-
Balance at end of period	**754**	980
Accumulated other comprehensive income/(loss) *(Note 8)*		
Balance at beginning of period	**1,632**	(435)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(1,266)**	605
Balance at end of period	**366**	170
Reciprocal shareholding		
Balance at beginning of period	**(83)**	(83)
Issuance of treasury stock	**(19)**	-
Balance at end of period	**(102)**	(83)
Total Enbridge Inc. shareholders equity	**20,676**	17,231
Noncontrolling interests		
Balance at beginning of period	**1,300**	2,015
Earnings attributable to noncontrolling interests	**7**	74
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	**(91)**	(111)
Change in foreign currency translation adjustment	**(55)**	157
Reclassification to earnings of realized cash flow hedges	**1**	(4)
Reclassification to earnings of unrealized cash flow hedges	**2**	(23)
	(143)	19
Comprehensive income/(loss) attributable to noncontrolling interests	**(136)**	93
Distributions	**(184)**	(158)
Contributions	**16**	525
Drop down of interest to Enbridge Energy Partners, L.P.	**-**	(304)
Dilution loss	**-**	(53)
Other	**(6)**	2
Balance at end of period	**990**	2,120

Total equity	**21,666**	19,351
Dividends paid per common share	**0.5300**	0.4650

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2016	2015
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings/(loss)	**1,347**	(221)
Depreciation and amortization	**559**	474
Deferred income taxes (recovery)/expense	**374**	(322)
Changes in unrealized (gains)/loss on derivative instruments, net *(Note 9)*	**(842)**	1,483
Cash distributions in excess of/(less than) equity earnings	**(40)**	46
Gain on disposition	**-**	(5)
Hedge ineffectiveness *(Note 9)*	**26**	(18)
Inventory revaluation allowance	**168**	43
Other	**147**	(106)
Changes in environmental liabilities, net of recoveries	**(9)**	(10)
Changes in operating assets and liabilities	**131**	157
	1,861	1,521
Investing activities		
Additions to property, plant and equipment	**(1,645)**	(1,590)
Joint venture financing	**(10)**	-
Long-term investments	**(133)**	(142)
Restricted long-term investments	**(12)**	(11)
Deposit for acquisition *(Note 13)*	**(54)**	-
Additions to intangible assets	**(27)**	(19)
Acquisition	**-**	(106)
Affiliate loans, net	**2**	3
Changes in restricted cash	**27**	(12)
	(1,852)	(1,877)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**243**	(456)
Net change in commercial paper and credit facility draws	**(1,164)**	1,021
Debenture and term note repayments	**-**	(376)
Contributions from noncontrolling interests	**16**	525
Distributions to noncontrolling interests	**(184)**	(158)
Contributions from redeemable noncontrolling interests	**4**	-
Distributions to redeemable noncontrolling interests	**(42)**	(27)
Common shares issued	**2,227**	8
Preference share dividends	**(73)**	(71)
Common share dividends	**(276)**	(241)
	751	225
Effect of translation of foreign denominated cash and cash equivalents	**(40)**	61
Increase/(decrease) in cash and cash equivalents	**720**	(70)
Cash and cash equivalents at beginning of period	**1,015**	1,261
Cash and cash equivalents at end of period	**1,735**	1,191

See accompanying notes to the unaudited interim consolidated financial statements.

4

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2016	December 31, 2015
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,735**	1,015
Restricted cash	**7**	34
Accounts receivable and other *(Note 4)*	**4,468**	5,430
Accounts receivable from affiliates	**6**	7
Inventory	**694**	1,111
	6,910	7,597
Property, plant and equipment, net	**63,251**	64,434
Long-term investments	**6,729**	7,008
Restricted long-term investments	**61**	49
Deferred amounts and other assets	**3,119**	3,160
Intangible assets, net	**1,304**	1,348
Goodwill	**77**	80
Deferred income taxes	**1,012**	839
	82,463	84,515
Liabilities and equity		
Current liabilities		
Bank indebtedness	**730**	361
Short-term borrowings	**473**	599
Accounts payable and other	**6,421**	7,351
Accounts payable to affiliates	**94**	48
Interest payable	**394**	324
Environmental liabilities	**155**	141
Current maturities of long-term debt *(Note 6)*	**2,429**	1,990
	10,696	10,814
Long-term debt *(Note 6)*	**36,543**	39,391
Other long-term liabilities	**5,482**	6,056
Deferred income taxes	**5,814**	5,915
	58,535	62,176
Contingencies *(Note 12)*		
Redeemable noncontrolling interests	**2,262**	2,141
Equity		
Share capital		
Preference shares	**6,515**	6,515
Common shares (929 and 868 outstanding at March 31, 2016 and December 31, 2015, respectively)	**9,828**	7,391
Additional paid-in capital	**3,315**	3,301
Retained earnings	**754**	142
Accumulated other comprehensive income *(Note 8)*	**366**	1,632
Reciprocal shareholding	**(102)**	(83)
Total Enbridge Inc. shareholders equity	**20,676**	18,898
Noncontrolling interests	**990**	1,300
	21,666	20,198
	82,463	84,515

Variable Interest Entities (Note 5)

*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 amended consolidated financial statements and notes thereto for the year ended December 31, 2015 filed on May 12, 2016. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, with the exception of an out-of-period adjustment further described in Note 3, Segmented Information, which management considers necessary to present fairly the Company s financial position as at March 31, 2016 and results of operations and cash flows for the three month s ended March 31, 2016 and 2015. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company s amended consolidated financial statements as at and for the year ended December 31, 2015, 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 business, as well as other factors such as the supply of and demand for crude oil and natural gas.

REPORTABLE SEGMENTS

Effective January 1, 2016, as a result of the recent changes from restructuring its Canadian Liquids Pipelines business (Canadian Restructuring Plan), Enbridge revised its reportable segments to better reflect the underlying operations of the Company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services, as discussed below. The Company believes this new format more clearly describes the financial performance of its business segments, provides increased transparency with respect to operational results and aligns with business segment decision making and management.

Comparative amounts presented on a segmented basis have been restated accordingly to be consistent with the current period reportable segments.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Mid-Continent and Gulf Coast, Southern Lights Pipeline, Bakken System and Feeder Pipelines and Other.

GAS DISTRIBUTION

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

GAS PIPELINES AND PROCESSING

Gas Pipelines and Processing consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include the Company s interests in the Alliance Pipeline, the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company s interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline, Canadian

Midstream assets located in northeast British Columbia and northwest Alberta and United States Midstream assets located primarily in Texas and Oklahoma.

GREEN POWER AND TRANSMISSION

Green Power and Transmission consists of the Company s investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas and Indiana.

ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company s volume commitments on Alliance Pipeline, Vector and other pipeline systems.

ELIMINATIONS AND OTHER

In addition, Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and elimination of transactions between segments required to present financial performance and financial position on a consolidated basis.

2. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Classification of Deferred Taxes on the Statements of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations

Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis. The new standard requires that an acquirer must recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria will simplify the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company s consolidated financial statements.

Amendments to the Consolidation Analysis

ASU 2015-02, issued in February 2015, revises the current consolidation guidance which results in a change in the determination of whether an entity consolidates certain types of legal entities. The new standard is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied on a full or modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-02 on a modified retrospective basis, which amended and clarified the guidance on VIEs. There was a significant change in the assessment of limited partnerships and other similar legal entities as VIEs, including the removal of the presumption that the general partner should consolidate a limited partnership. As a result, the Company has determined that a majority of the limited partnerships that are currently consolidated or equity accounted for are VIEs. The amended guidance did not impact the Company s accounting treatment of such entities, however, material disclosures for VIEs have been provided, as necessary.

3. SEGMENTED INFORMATION

Effective January 1, 2016, the Company revised its reportable segments *(Note 1).* Revisions to the segmented information presentation on a retrospective basis include:

- The replacement of the previous segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate with new segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services;

- Presenting the Earnings before interest and income taxes of each segment as opposed to Earnings attributable to Enbridge Inc. common shareholders. Amounts related to Interest expense, Income taxes, Earnings attributable to noncontrolling interests and redeemable noncontrolling interests and Preference share dividends are now reported on a consolidated basis.

Segmented information for the three months ended March 31, 2016 and 2015 are as follows:

Three months ended March 31, 2016	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,613**	**1,166**	**652**	**134**	**4,311**	**(81)**	**8,795**
Commodity and gas distribution costs	**(2)**	**(766)**	**(483)**	**1**	**(4,296)**	**81**	**(5,465)**
Operating and administrative	**(766)**	**(134)**	**(119)**	**(40)**	**(15)**	**(6)**	**(1,080)**
Depreciation and amortization	**(346)**	**(80)**	**(74)**	**(48)**	**-**	**(11)**	**(559)**
Environmental costs, net of recoveries	**(17)**	**-**	**-**	**-**	**-**	**-**	**(17)**
	1,482	**186**	**(24)**	**47**	**-**	**(17)**	**1,674**
Income/(loss) from equity investments	**113**	**43**	**70**	**2**	**(2)**	**-**	**226**
Other income/(expense)	**17**	**10**	**15**	**-**	**(4)**	**238**	**276**
Earnings/(loss) before interest and income taxes	**1,612**	**239**	**61**	**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	**1,332**	**248**	**52**	**7**	**-**	**6**	**1,645**

Three months ended March 31, 2015	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	791	1,792	1,127	131	4,207	(119)	7,929
Commodity and gas distribution costs	(1)	(1,368)	(965)	1	(4,190)	117	(6,406)
Operating and administrative	(681)	(134)	(115)	(29)	(18)	(14)	(991)
Depreciation and amortization	(280)	(77)	(65)	(46)	-	(6)	(474)
Environmental costs, net of recoveries	11	-	-	-	-	-	11
	(160)	213	(18)	57	(1)	(22)	69
Income/(loss) from equity investments	60	14	62	1	(2)	(2)	133
Other income/(expense)	(45)	12	(8)	1	-	(417)	(457)
Earnings/(loss) before interest and income taxes	(145)	239	36	59	(3)	(441)	(255)
Interest expense							(251)
Income taxes recovery							285
Loss							(221)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							(90)
Preference share dividends							(72)
Loss attributable to Enbridge Inc. common shareholders							(383)
Additions to property, plant and equipment	1,322	106	119	29	-	14	1,590

OUT-OF-PERIOD ADJUSTMENT

Earnings attributable to Enbridge Inc. common shareholders for the three months ended March 31, 2015 were increased by an out-of-period adjustment of $71 million in respect of an overstatement of deferred income tax expense in 2013 and 2014.

TOTAL ASSETS

	March 31, 2016	December 31, 2015
(millions of Canadian dollars)		
Liquids Pipelines	**51,156**	52,015
Gas Distribution	**9,618**	9,901
Gas Pipelines and Processing	**10,888**	11,559
Green Power and Transmission	**4,931**	4,977
Energy Services	**1,543**	1,889
Eliminations and Other	**4,327**	4,174
	82,463	84,515

4. 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 Enbridge Energy Partners, L.P. (EEP) subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to

December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$252 million ($326 million) and US$317 million ($439 million) as at March 31, 2016 and December 31, 2015, respectively.

5. VARIABLE INTEREST ENTITIES

On January 1, 2016, the Company adopted ASU 2015-02 using the modified retrospective transition approach, which amended and clarified the guidance on VIEs. While the new guidance did not impact the Company s accounting treatment conclusion on various entities, additional disclosures regarding these VIEs are necessary. These disclosures are included below.

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

The Company assesses all variable interests in the entity and uses its judgment when determining if the Company is the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reconsideration of whether an entity is a VIE occurs when there are certain changes in the facts and circumstances related to a VIE. The Company assesses the primary beneficiary determination for a VIE on an ongoing basis.

CONSOLIDATED VARIABLE INTEREST ENTITIES

Enbridge Energy Partners, L.P.

EEP is a publicly-traded Delaware limited partnership and is considered a VIE as its limited partners do not have substantive kick-out rights or participating rights. Enbridge, through its wholly-owned subsidiary, Enbridge Energy Company, Inc. (EECI), has the power to direct EEP s activities that have a significant impact on EEP s economic performance. Along with a 35.6% economic interest held through an indirect common interest and preferred unit interest through EECI, the Company, through its 100% ownership of EECI, is the primary beneficiary of EEP. The public owns the remaining interests in EEP.

Enbridge Income Partners LP

Enbridge Income Partners LP (EIPLP), formed in 2002, is involved in the generation, transportation and storage of energy through interests in its Liquids Pipelines business, including the Canadian Mainline, its 50.0% interest in the Alliance Pipeline, which transports natural gas, and its renewable and alternative power generation facilities. EIPLP is a partnership between the Company and Enbridge Commercial Trust (ECT). EIPLP is considered a VIE as its limited partners lack substantive kick-out rights and participating rights. Through a majority ownership of EIPLP s General Partner, 100% ownership of Enbridge Management Services Inc. (a service provider for EIPLP), and 55.6% of direct common interest in EIPLP, the Company has the power to direct the activities that most significantly impact EIPLP s economic performance and have the obligation to absorb losses and the right to receive residual returns that are potentially significant to EIPLP, making the Company the primary beneficiary of EIPLP. As at March 31, 2016, the Company s economic interest in EIPLP was 81.9%.

Other Limited Partnerships

By virtue of a lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly owned by Enbridge and/or its subsidiaries are considered VIEs. As these entities are 100% owned and directed by Enbridge with no third parties having the ability to direct any of the significant activities, the Company is considered the primary beneficiary.

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

March 31,	2016
(millions of Canadian dollars)	
Cash and cash equivalents	621
Restricted cash	1
Accounts receivable and other	862
Accounts receivable from affiliates	3
Inventory	26
	1,513
Property, plant and equipment, net	44,124
Long-term investments	952
Restricted long-term investments	56
Deferred amounts and other assets	1,757
Intangible assets, net	465
Goodwill	29
Deferred income taxes	244
	49,140
Bank indebtedness	(293)
Accounts payable and other	(1,714)
Accounts payable to affiliates	(82)
Interest payable	(211)
Environmental liabilities	(152)
Current maturities of long-term debt	(404)
	(2,856)
Long-term debt	(16,525)
Other long-term liabilities	(1,305)
Deferred income taxes	(1,469)
	(22,155)
Net assets before noncontrolling interests	26,985

The Company does not have an obligation to provide financial support to any of the consolidated VIEs, with the exception of EIPLP. The Company is required, when called on by Enbridge Income Fund Holdings Inc. (ENF), to backstop equity funding required by EIPLP to undertake the growth program embedded in the assets it acquired in the Canadian Restructuring Plan.

Other Consolidated VIEs

Enbridge Income Fund (the Fund), ECT, Magicat Holdco LLC, and Keechi Holdings L.L.C. are also entities that are considered VIEs and consolidated by the Company. There have been no significant changes to Enbridge s interest in these entities since December 31, 2015.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

The Company currently holds several equity investments in limited partnerships that are assessed to be VIEs due to limited partners not having substantive kick-out rights or participating rights. Enbridge has determined that it does not have the power to direct the activities of the VIEs that most significantly impact the VIEs economic performance. Specifically, the power to direct the activities of a majority of these VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee who makes significant decisions for the VIE and none of the partners may make major decisions unilaterally.

The carrying amount of the Company s interest in VIEs that are unconsolidated and its estimated maximum exposure to loss as at March 31, 2016 is presented below.

March 31, 2016	Carrying Amount of Investment in VIE	Enbridge s Maximum Exposure to Loss
(millions of Canadian dollars)		
Vector Pipeline L.P.[1]	149	149
Aux Sable Liquid Products L.P.[1]	175	175
Rampion Offshore Wind Limited[2]	220	405
Eddystone Rail Company, LLC[3]	156	204
Illinois Extension Pipeline Company, L.L.C.[1]	740	740
Other[1]	15	15
	1,455	1,688

1 At March 31, 2016, the maximum exposure to loss for these entities are limited to the Company s equity investment as these companies are in operation and self-sustaining.

2 At March 31, 2016, the maximum exposure to loss includes the portion of the Company s parental guarantee that has been committed in project construction contracts in which the Company would be liable for in the event of default by the VIE.

3 At March 31, 2016, the maximum exposure to loss includes the carrying value of an outstanding loan issued by the Company.

The Company does not have an obligation to and did not provide any additional financial support to the VIEs during the period ended March 31, 2016.

6. DEBT

The following table provides details of the Company s committed credit facilities as at March 31, 2016 and December 31, 2015.

		March 31, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Inc.	2017-2020	**6,866**	**3,643**	**3,223**	6,988
Enbridge (U.S.) Inc.	2017	**4,189**	**1,427**	**2,762**	4,470
Enbridge Energy Partners, L.P.	2017-2020	**3,372**	**2,386**	**986**	3,598
Enbridge Gas Distribution Inc.	2017-2019	**1,009**	**479**	**530**	1,010
Enbridge Income Fund	2018	**1,500**	**11**	**1,489**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**26**	**-**	**26**	28
Enbridge Pipelines Inc.	2017	**3,000**	**1,922**	**1,078**	3,000

Enbridge Southern Lights LP	2017	**5**	**-**	**5**	5
Midcoast Energy Partners, L.P.	2018	**1,051**	**571**	**480**	1,121
Total committed credit facilities		**21,018**	**10,439**	**10,579**	21,720

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

In addition to the committed credit facilities noted above, the Company also has $334 million (December 31, 2015 - $349 million) of uncommitted demand credit facilities, of which $123 million (December 31, 2015 - $185 million) was unutilized as at March 31, 2016.

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 2020.

Commercial paper and credit facility draws, net of short-term borrowings, of $9,816 million (December 31, 2015 - $11,344 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

7. SHARE CAPITAL

COMMON SHARES

March 31,	**2016** Number of Shares	**2016** Amount	2015 Number of Shares	2015 Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of period	**868**	**7,391**	852	6,669
Common shares issued[1]	**56**	**2,241**	-	-
Dividend Reinvestment and Share Purchase Plan	**4**	**184**	2	155
Shares issued on exercise of stock options	**1**	**12**	1	13
Balance at end of period	**929**	**9,828**	855	6,837

1 Gross proceeds - $2,300 million (2015 - nil); net issuance costs - $59 million (2015 - nil).

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company s pro-rata weighted average interest in its own common shares of 12 million (2015 - 12 million) for the three months ended March 31, 2016, resulting from the Company s reciprocal investment in Noverco.

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

Three months ended March 31,	**2016**	2015
(number of shares in millions)		
Weighted average shares outstanding	**876**	841
Effect of dilutive options	**6**	-
Diluted weighted average shares outstanding	**882**	841

For the three months ended March 31, 2016, 20,150,772 anti-dilutive stock options (2015 - 40,593,590) with a weighted average exercise price of $49.62 (2015 - $38.77) were excluded from the diluted earnings per common share calculation.

8. 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, 2016 and 2015 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, 2016	**(688)**	**(795)**	**3,365**	**37**	**(287)**	**1,632**
Other comprehensive income/(loss) retained in AOCI	**(459)**	**409**	**(1,314)**	**(8)**	**-**	**(1,372)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	**29**	**-**	**-**	**-**	**-**	**29**
Commodity contracts2	**(3)**	**-**	**-**	**-**	**-**	**(3)**
Foreign exchange contracts3	**2**	**-**	**-**	**-**	**-**	**2**
Other contracts4	**(26)**	**-**	**-**	**-**	**-**	**(26)**
Amortization of pension and OPEB actuarial loss5	**-**	**-**	**-**	**-**	**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**

	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, 2015	(488)	108	309	(5)	(359)	(435)
Other comprehensive income/(loss) retained in AOCI	(515)	(457)	1,413	10	-	451
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	(7)	-	-	-	-	(7)
Commodity contracts2	(10)	-	-	-	-	(10)
Other contracts4	5	-	-	-	-	5
Amortization of pension and OPEB actuarial loss5	-	-	-	-	6	6
	(527)	(457)	1,413	10	6	445
Tax impact						
Income tax on amounts retained in AOCI	132	31	-	(1)	-	162
Income tax on amounts reclassified to earnings	-	-	-	-	(2)	(2)
	132	31	-	(1)	(2)	160
Balance at March 31, 2015	(883)	(318)	1,722	4	(355)	170

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

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

3 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*

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

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

9. 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 interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

The Company s earnings and cash flows are also exposed to variability in longer-term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 3.4%.

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

Commodity Price Risk

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

Equity Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges as at March 31, 2016 or December 31, 2015.

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, 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	**5**	**4**	**22**	**31**	**(10)**	**21**
Interest rate contracts	**2**	**-**	**-**	**2**	**(2)**	**-**
Commodity contracts	**9**	**-**	**527**	**536**	**(119)**	**417**
Other contracts	**-**	**-**	**-**	**-**	**-**	**-**
	16	**4**	**549**	**569**	**(131)**	**438**
Deferred amounts and other assets						
Foreign exchange contracts	**82**	**6**	**23**	**111**	**(109)**	**2**
Interest rate contracts	**-**	**-**	**-**	**-**	**-**	**-**
Commodity contracts	**13**	**-**	**144**	**157**	**(23)**	**134**
Other contracts	**-**	**-**	**-**	**-**	**-**	**-**
	95	**6**	**167**	**268**	**(132)**	**136**
Accounts payable and other						
Foreign exchange contracts	**-**	**(116)**	**(569)**	**(685)**	**10**	**(675)**
Interest rate contracts	**(611)**	**-**	**(186)**	**(797)**	**2**	**(795)**
Commodity contracts	**-**	**-**	**(440)**	**(440)**	**119**	**(321)**
Other contracts	**-**	**-**	**(2)**	**(2)**	**-**	**(2)**
	(611)	**(116)**	**(1,197)**	**(1,924)**	**131**	**(1,793)**
Other long-term liabilities						
Foreign exchange contracts	**-**	**(162)**	**(2,009)**	**(2,171)**	**109**	**(2,062)**
Interest rate contracts	**(752)**	**-**	**(219)**	**(971)**	**-**	**(971)**
Commodity contracts	**-**	**-**	**(184)**	**(184)**	**23**	**(161)**
Other contracts	**(5)**	**-**	**(3)**	**(8)**	**-**	**(8)**
	(757)	**(162)**	**(2,415)**	**(3,334)**	**132**	**(3,202)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**87**	**(268)**	**(2,533)**	**(2,714)**	**-**	**(2,714)**
Interest rate contracts	**(1,361)**	**-**	**(405)**	**(1,766)**	**-**	**(1,766)**
Commodity contracts	**22**	**-**	**47**	**69**	**-**	**69**

Other contracts	**(5)**	**-**	**(5)**	**(10)**	**-**	**(10)**
	(1,257)	**(268)**	**(2,896)**	**(4,421)**	**-**	**(4,421)**

16

December 31, 2015 *(millions of Canadian dollars)*	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
Accounts receivable and other						
Foreign exchange contracts	6	2	2	10	(3)	7
Interest rate contracts	2	-	-	2	(2)	-
Commodity contracts	7	-	772	779	(211)	568
Other contracts	-	-	-	-	-	-
	15	2	774	791	(216)	575
Deferred amounts and other assets						
Foreign exchange contracts	114	4	10	128	(127)	1
Interest rate contracts	18	-	-	18	(14)	4
Commodity contracts	7	-	220	227	(77)	150
Other contracts	-	-	-	-	-	-
	139	4	230	373	(218)	155
Accounts payable and other						
Foreign exchange contracts	(1)	(106)	(765)	(872)	3	(869)
Interest rate contracts	(379)	-	(185)	(564)	2	(562)
Commodity contracts	-	-	(501)	(501)	194	(307)
Other contracts	(2)	-	(6)	(8)	-	(8)
	(382)	(106)	(1,457)	(1,945)	199	(1,746)
Other long-term liabilities						
Foreign exchange contracts	-	(252)	(2,796)	(3,048)	127	(2,921)
Interest rate contracts	(405)	-	(224)	(629)	14	(615)
Commodity contracts	-	-	(260)	(260)	77	(183)
Other contracts	(8)	-	(5)	(13)	-	(13)
	(413)	(252)	(3,285)	(3,950)	218	(3,732)
Total net derivative asset/(liability)						
Foreign exchange contracts	119	(352)	(3,549)	(3,782)	-	(3,782)
Interest rate contracts	(764)	-	(409)	(1,173)	-	(1,173)
Commodity contracts	14	-	231	245	(17)1	228
Other contracts	(10)	-	(11)	(21)	-	(21)
	(641)	(352)	(3,738)	(4,731)	(17)	(4,748)

1 *Amount available for offset includes $17 million of cash collateral.*

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

March 31, 2016	2016	2017	2018	2019	2020	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**544**	**413**	**2**	**2**	**2**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,374**	**3,229**	**3,156**	**2,645**	**2,318**	**787**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**52**	**77**	**6**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**-**	**89**	**25**	**144**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**6,215**	**7,331**	**4,343**	**1,494**	**148**	**394**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,178**	**3,278**	**1,903**	**762**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**51**	**48**	**-**	**-**	**-**	**-**
	(99)	**(72)**	**(13)**	**2**	**1**	**-**

Commodity contracts - natural gas *(billions of cubic feet)*						
Commodity contracts - crude oil *(millions of barrels)*	**(6)**	**(18)**	**(9)**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(7)**	**-**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**42**	**40**	**30**	**31**	**35**	**(35)**

December 31, 2015	2016	2017	2018	2019	2020	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	172	413	2	2	2	-
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	3,059	3,213	3,133	2,630	2,303	787
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	70	77	6	-	-	-
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	-	-	-	89	25	144
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	8,382	7,604	4,536	1,574	156	406
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	4,291	3,371	1,960	773	-	-
Equity contracts *(millions of Canadian dollars)*	51	48	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	(126)	(209)	(17)	2	1	-
Commodity contracts - crude oil *(millions of barrels)*	(6)	(17)	(9)	-	-	-
Commodity contracts - NGL *(millions of barrels)*	(5)	1	-	-	-	-
Commodity contracts - power *(megawatt hours (MWH))*	40	40	30	31	35	(35)

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

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

		Three months ended March 31,	
		2016	2015
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
	Foreign exchange contracts	**(35)**	45
	Interest rate contracts	**(576)**	(664)
	Commodity contracts	**16**	19
	Other contracts	**31**	(8)
Net investment hedges			
	Foreign exchange contracts	**84**	(123)
		(480)	(731)
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*			
	Foreign exchange contracts[1]	**3**	-
	Interest rate contracts[2]	**(21)**	10
	Commodity contracts[3]	**(8)**	(20)
	Other contracts[4]	**(26)**	5
		(52)	(5)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]		**26**	(23)
Commodity contracts[3]		**-**	5
		26	(18)

1 *Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.*

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

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

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

The Company estimates that $94 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 45 months as at March 31, 2016.

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,	
	2016	2015
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**1,016**	(1,293)
Interest rate contracts[2]	**4**	-
Commodity contracts[3]	**(184)**	(192)
Other contracts[4]	**6**	2
Total unrealized derivative fair value gain/(loss)	**842**	(1,483)

1 *Reported within Transportation and other services revenues (2016 - $582 million gain; 2015 - $795 million loss) and Other income/(expense) (2016 - $434 million gain; 2015 - $498 million loss) in the Consolidated Statements of Earnings.*

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

3 *Reported within Transportation and other services revenues (2016 - $39 million gain; 2015 - $18 million loss), Commodity sales (2016 - $285 million loss; 2015 - nil), Commodity costs (2016 - $76 million gain; 2015 - $143 million loss) and Operating and administrative expense (2016 - $14 million loss; 2015 - $31 million loss) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. The Company, through committed credit facilities with a diversified group of banks and institutions, targets to maintain sufficient liquidity to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2016. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

	March 31, 2016	December 31, 2015
(millions of Canadian dollars)		
Canadian financial institutions	**51**	47
United States financial institutions	**348**	450
European financial institutions	**90**	95
Asian financial institutions	**2**	4
Other[1]	**325**	213
	816	809

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

As at March 31, 2016, the Company had provided letters of credit totalling $251 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, 2016 and $17 million of cash collateral as at December 31, 2015.

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

Level 3

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

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

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

March 31, 2016	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**31**	**-**	**31**
Interest rate contracts	**-**	**2**	**-**	**2**
Commodity contracts	**6**	**166**	**364**	**536**
	6	**199**	**364**	**569**
Long-term derivative assets				
Foreign exchange contracts	**-**	**111**	**-**	**111**
Commodity contracts	**-**	**113**	**44**	**157**
	-	**224**	**44**	**268**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(685)**	**-**	**(685)**
Interest rate contracts	**-**	**(797)**	**-**	**(797)**
Commodity contracts	**(7)**	**(92)**	**(341)**	**(440)**
Other contracts	**-**	**(2)**	**-**	**(2)**
	(7)	**(1,576)**	**(341)**	**(1,924)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(2,171)**	**-**	**(2,171)**
Interest rate contracts	**-**	**(971)**	**-**	**(971)**
Commodity contracts	**-**	**(15)**	**(169)**	**(184)**
Other contracts	**-**	**(8)**	**-**	**(8)**
	-	**(3,165)**	**(169)**	**(3,334)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,714)**	**-**	**(2,714)**
Interest rate contracts	**-**	**(1,766)**	**-**	**(1,766)**
Commodity contracts	**(1)**	**172**	**(102)**	**69**
Other contracts	**-**	**(10)**	**-**	**(10)**
	(1)	**(4,318)**	**(102)**	**(4,421)**

December 31, 2015	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	10	-	10
Interest rate contracts	-	2	-	2
Commodity contracts	14	210	555	779
Other contracts	-	-	-	-
	14	222	555	791
Long-term derivative assets				
Foreign exchange contracts	-	128	-	128
Interest rate contracts	-	18	-	18
Commodity contracts	-	121	106	227
Other contracts	-	-	-	-
	-	267	106	373
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(872)	-	(872)
Interest rate contracts	-	(564)	-	(564)
Commodity contracts	(3)	(130)	(368)	(501)
Other contracts	-	(8)	-	(8)
	(3)	(1,574)	(368)	(1,945)
Long-term derivative liabilities				
Foreign exchange contracts	-	(3,048)	-	(3,048)
Interest rate contracts	-	(629)	-	(629)
Commodity contracts	-	(21)	(239)	(260)
Other contracts	-	(13)	-	(13)
	-	(3,711)	(239)	(3,950)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(3,782)	-	(3,782)
Interest rate contracts	-	(1,173)	-	(1,173)
Commodity contracts	11	180	54	245
Other contracts	-	(21)	-	(21)
	11	(4,796)	54	(4,731)

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

March 31, 2016	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial1						
Natural gas	(5)	Forward gas price	2.15	4.24	3.11	$/mmbtu3
NGL	14	Forward NGL price	0.22	1.20	0.78	$/gallon
Power	(152)	Forward power price	18.50	69.55	49.76	$/MWH
Commodity contracts - physical1						
Natural gas	(22)	Forward gas price	1.06	4.25	2.58	$/mmbtu3
Crude	(35)	Forward crude price	36.70	53.06	50.47	$/barrel
NGL	4	Forward NGL price	0.22	1.20	0.71	$/gallon
Commodity options2						
Crude	40	Option volatility	26%	37%	33%	
NGL	52	Option volatility	8%	100%	38%	
Power	2	Option volatility	22%	109%	25%	
	(102)					

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

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

3 One million British thermal units (mmbtu).

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

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

	Three months ended March 31, **2016**	2015
(millions of Canadian dollars)		
Level 3 net derivative asset at beginning of period	**54**	149
Total gains/(loss)		
Included in earnings[1]	**(40)**	(7)
Included in OCI	**7**	2
Settlements	**(123)**	(151)
Level 3 net derivative liability at end of period	**(102)**	(7)

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, 2016 or 2015.

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 $122 million as at March 31, 2016 (December 31, 2015 - $126 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $385 million as at March 31, 2016 (December 31, 2015 - $344 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. As at March 31, 2016, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2015 - $580 million).

As at March 31, 2016, the Company s long-term debt had a carrying value of $38,972 million (December 31, 2015 - $41,381 million) and a fair value of $39,477 million (December 31, 2015 - $41,045 million).

NET INVESTMENT HEDGES

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

During the three months ended March 31, 2016, the Company recognized an unrealized foreign exchange gain on the translation of United States dollar denominated debt of $297 million (2015 - unrealized loss of $331 million) and an unrealized gain on the change in fair value of its outstanding foreign exchange forward contracts of $84 million (2015 - unrealized loss of $124 million) in OCI. The Company did not recognize any amount (2015 - realized loss of $2 million) in OCI associated with the settlement of foreign exchange forward contracts but had recognized a realized gain of $28 million (2015 - nil) 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, 2016 (2015 - nil).

10. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2016 was 23.6% (2015 - 56.3%). The higher effective tax rate in 2015 was primarily attributable to the rate regulated tax benefit and other permanent items relative to the loss in the first three months of 2015. The effective income tax rate for the three months ended March 31, 2015 was further increased by an out-of-period adjustment.

11. RETIREMENT AND POSTRETIREMENT BENEFITS

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

NET BENEFIT COSTS RECOGNIZED

	Three months ended March 31,	
	2016	2015
(millions of Canadian dollars)		
Benefits earned during the period	**42**	44
Interest cost on projected benefit obligations	**26**	27
Expected return on plan assets	**(38)**	(36)
Amortization of actuarial loss	**9**	12
Net benefit costs on an accrual basis[1,2]	**39**	47

1 Included in net benefit costs for the three months ended March 31, 2016 are costs related to OPEB of $4 million (2015 - $3 million).

2 For the three months ended March 31, 2016, offsetting regulatory liability of $2 million (2015 - nil) have been recorded to the extent pension and OPEB costs are expected to be refunded to, or collected from, customers in future rates.

12. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 35.6% combined direct and indirect economic interest in EEP, which is consolidated with noncontrolling interests.

Lakehead System Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

As at March 31, 2016, EEP s total cost estimate for the Line 6B crude oil release is US$1.2 billion ($195 million after-tax attributable to Enbridge). As at March 31, 2016, the liability increased by US$15 million, as compared to December 31, 2015, due to an increase in estimated civil penalties under the Clean Water Act of the United States as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated as at March 31, 2016. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP s remediation spending through March 31, 2016, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under prior or existing insurance policies. As at March 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 aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of US$145 million of coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP s claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was predicated on the outcome of the recovery from that insurer. EEP received a partial recovery of US$42 million from the other remaining insurers and amended its lawsuit such that it included only one insurer.

Enbridge has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2016 through April 30, 2017 with a liability program aggregate limit of US$900 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Four 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 the Company s results of operations or financial condition.

As at March 31, 2016, included in EEP s total estimated costs related to the Line 6B crude oil release is US$63 million in fines and penalties. Of this amount, US$55 million related to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$55 million represents EEP s estimate of the amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures could be material. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

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.

13. SUBSEQUENT EVENTS

On April 1, 2016, the Company closed on a previously announced purchase and sales agreement to acquire a 100% interest in the Tupper Main and Tupper West gas plants and associated pipelines for approximately $538 million. The transaction will be accounted for as a business combination by applying the acquisition method, and accordingly, the purchase price will be allocated to the assets acquired and liabilities assumed based upon their fair value at the acquisition date. The Company is in the process of finalizing the purchase price allocation.

On April 20, 2016, ENF completed a public equity offering of 20.4 million common shares at a price of $28.25 per common share (the Offering Price) for gross proceeds of $575 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.1 million common shares at a price of $28.25 per share, for total proceeds of $143 million, on a private placement basis to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the sale of the common shares to subscribe for additional trust units of the Fund at the Offering Price.