ENBRIDGE INC
Form 6-K
July 29, 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 July 29, 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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 six months ended June 30, 2016.
- Interactive Data File.

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: July 29, 2016

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

Vice President & Corporate Secretary

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ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

June 30, 2016

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2016

This Management s Discussion and Analysis (MD&A) dated July 29, 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 and six months ended June 30, 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 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; and

- Presenting the Earnings before interest and income taxes (EBIT) of each segment as opposed to Earnings attributable to Enbridge 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 and six months ended June 30, 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.

IMPACT OF 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 more than 80,000 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 temporarily 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.

The Company coordinated 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, and restarted and returned the majority of its regional pipeline systems to normal operation by the end of May 2016.

Oil sands production from facilities in the vicinity of Fort McMurray, Alberta was curtailed longer than originally anticipated, given the severity and longevity of the wildfires. On average Enbridge s mainline system deliveries were lower by approximately 255,000 barrels per day (bpd) during the months of May and June 2016, which represents an approximate 10% decrease in throughput compared with the throughput that the Company was delivering prior to the wildfires. The impact of reduced system deliveries on revenues negatively impacted the Company s adjusted EBIT and available cash flow from operations (ACFFO) by approximately $74 million for the three and six months ended June 30, 2016. They also reduced the Company s adjusted earnings and adjusted earnings per share by $26 million and $0.03, respectively, for the three and six months ended June 30, 2016. Oil sands production substantially came back online by the end of June 2016 and throughput on the Company s mainline system and overall system utilization are expected to return to levels anticipated at the outset of the year, during the third quarter of 2016.

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**643**	1,097	**2,255**	952
Gas Distribution	**83**	78	**322**	317
Gas Pipelines and Processing	**19**	(411)	**80**	(375)
Green Power and Transmission	**41**	43	**90**	102
Energy Services	**(7)**	67	**(13)**	64
Eliminations and Other	**(48)**	65	**173**	(376)
Earnings/(loss) before interest and income taxes	**731**	939	**2,907**	684
Interest expense	**(369)**	(284)	**(781)**	(535)
Income taxes recovery/(expense)	**(10)**	(232)	**(427)**	53
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	224	**(41)**	134
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Earnings attributable to common shareholders	**301**	577	**1,514**	194
Earnings per common share	**0.33**	0.68	**1.69**	0.23
Diluted earnings per common share	**0.33**	0.67	**1.67**	0.23

EARNINGS/(LOSS) BEFORE INTEREST AND INCOME TAXES

For the three and six months ended June 30, 2016, EBIT was $731 million and $2,907 million, respectively, compared with $939 million and $684 million for the three and six months ended June 30, 2015. As discussed below in *Adjusted EBIT*, the Company has continued to deliver strong earnings growth from a majority of its businesses, offset partly by the impacts of the northeastern Alberta wildfires as discussed above. The positive impact of this growth and the comparability of the Company s earnings are also impacted by a number of unusual, non-recurring or non-operating factors that are enumerated in the Non-GAAP Reconciliation tables and discussed in the results for each reporting segment, the most significant of which are changes in unrealized derivative fair value gains and losses. For the three months ended June 30, 2016, the Company s EBIT reflected a $98 million unrealized derivative fair value loss compared with $366 million of unrealized derivative fair value gain in the corresponding 2015 period. For the six months ended June 30, 2016, the Company s EBIT reflected an $834 million unrealized derivative fair value gain compared with $1,042 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.

In addition, the comparability of period-over-period EBIT was impacted by the recognition of an impairment of $176 million ($103 million after-tax attributable to Enbridge) related to Enbridge s 75% joint venture interest in Eddystone Rail, a rail-to-barge transloading facility located in the greater Philadelphia, Pennsylvania area that delivers Bakken and other light sweet crude oil to Philadelphia area refineries. Due to a significant decrease in price spreads between Bakken crude oil and West Africa/Brent crude oil and increased competition in the region, demand for Eddystone Rail services dropped significantly, resulting in an impairment of this facility in the second quarter of 2016. The comparability of period-over-period EBIT was also impacted by a goodwill impairment charge of $440 million ($167 million after-tax attributable to Enbridge) recognized in the second quarter of 2015 related to Enbridge Energy Partners, L.P. s (EEP) natural gas and NGL businesses. Also impacting the comparability of period-over-period EBIT was a $21 million charge ($12 million after-tax attributable to Enbridge) for costs incurred to bring pipelines and facilities back into service following the northeastern Alberta wildfires in the second quarter of 2016.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $301 million for the three months ended June 30, 2016, or $0.33 per common share, compared with earnings of $577 million, or $0.68 per common share, for the three months ended June 30, 2015. Earnings attributable to common shareholders were $1,514 million for the six months ended June 30, 2016, or $1.69 per common share, compared with earnings of $194 million, or $0.23 per common share, for the six months ended June 30, 2015.

In addition to the factors discussed in *Earnings/(Loss) Before Interest and Income Taxes* above and in *Adjusted Earnings*, the comparability of Earnings 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. The comparability of the Company s six-month period-over-period operating results was also impacted by 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 , likely and similar words suggesting future outcomes or statements regarding 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 ACFFO; expected future cash flows; expectations regarding the impacts of the wildfires in northeastern Alberta, including on adjusted EBIT and ACFFO; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for the Company s commercially secured growth program; estimated cost and impact to the Company s overall financial performance of complying with the settlement consent decree related to Line 6B and Line 6A; estimated future dividends; 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 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 wildfires in northeastern Alberta; cost of complying with the settlement consent decree related to Line 6B and Line 6A; impact of the dividend policy on the Company s future cash flows; credit ratings; capital project funding; expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and 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, ACFFO or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labour and construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; the impact of weather; and customer 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, commodity prices,

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supply of and demand for commodities and the settlement consent decree related to Line 6B and Line 6A, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted EBIT, adjusted earnings/(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 give 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.

NON-GAAP RECONCILIATION EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Earnings before interest and income taxes	**731**	939	**2,907**	684
Adjusting items[1]:				
Changes in unrealized derivative fair value (gains)/loss[2]	**98**	(366)	**(834)**	1,042
Goodwill impairment loss	**-**	440	**-**	440
Assets and investment impairment loss	**187**	20	**187**	20
Unrealized intercompany foreign exchange (gains)/loss	**(5)**	16	**55**	(55)
Hydrostatic testing	**-**	-	**(12)**	-
Make-up rights adjustments	**48**	(15)	**115**	(13)
Northeastern Alberta wildfires pipelines and facilities restart costs	**21**	-	**21**	-
Leak remediation costs, net of leak insurance recoveries	**1**	8	**16**	(4)
Warmer/(colder) than normal weather	**(9)**	8	**8**	(37)
Employee severance and restructuring costs	**8**	-	**8**	-
Gains on sale of non-core assets	**-**	(28)	**-**	(28)
Project development and transaction costs	**3**	18	**3**	21
Other	**6**	9	**(11)**	10
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Interest expense	**(369)**	(284)	**(781)**	(535)
Income taxes recovery/(expense)	**(10)**	(232)	**(427)**	53
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	224	**(41)**	134
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Adjusting items in respect of[3]:				
Interest expense	**6**	(7)	**24**	(49)
Income taxes	**(121)**	132	**120**	(267)
Noncontrolling interests and redeemable noncontrolling interests	**(88)**	(307)	**(95)**	(301)
Adjusted earnings	**456**	505	**1,119**	973

1 The above table summarizes adjusting items by nature. For a detailed listing of adjusting items by segment, refer to individual segment discussions.

2 Changes in unrealized derivative fair value gains and losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.

3 These items were impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items above. Also included in income taxes is 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.

NON-GAAP RECONCILIATION ADJUSTED EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**922**	809	**2,006**	1,540
Gas Distribution	**73**	96	**313**	294
Gas Pipelines and Processing	**90**	74	**177**	164
Green Power and Transmission	**40**	43	**88**	100
Energy Services	**47**	78	**48**	106
Eliminations and Other	**(83)**	(51)	**(169)**	(124)
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Interest expense[1]	**(363)**	(291)	**(757)**	(584)
Income taxes[1]	**(131)**	(100)	**(307)**	(214)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(68)**	(83)	**(136)**	(167)
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Adjusted earnings	**456**	505	**1,119**	973
Adjusted earnings per common share	**0.50**	0.60	**1.25**	1.15

1 These balances are presented net of adjusting items.

Adjusted EBIT

For the three and six months ended June 30, 2016, adjusted EBIT was $1,089 million and $2,463 million, respectively, an increase of $40 million and $383 million over the corresponding three and six-month periods 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 and Regional Oil Sands System contributions increased in the first half of 2016 primarily due to higher period-over-period mainline system throughput that resulted from strong oil sands production in western Canada combined with contributions from new assets placed into service. However, the positive effect of increased capacity on liquids pipelines throughput was substantially negated in the second quarter by the impact of extreme wildfires in northeastern Alberta. The northeastern Alberta wildfires resulted in a curtailment of production from oil sands facilities and certain of the Company s upstream pipelines and terminal facilities were temporarily shut down resulting in a disruption of service on Enbridge s Regional Oil Sands System with corresponding impacts on Enbridge s downstream pipelines deliveries, including Canadian Mainline and the Lakehead System. Reduced system deliveries resulted in a negative impact of approximately $74 million on the Company s adjusted EBIT for the three and six-month periods in 2016. Growth in Canadian Mainline adjusted EBIT was also affected by a lower average International Joint Tariff (IJT) Residual Benchmark Toll, which decreased effective April 1, 2016 and, together with the impact of the wildfires, resulted in a quarter-over-quarter decrease in Canadian Mainline adjusted EBIT.

The Lakehead System delivered strong operating performance driven by higher throughput and contributions from new assets placed into service in 2015. Deliveries to the Lakehead System from the Canadian Mainline were lower during the second quarter as a result of the wildfires, but the impact on financial performance was relatively modest due to the higher Lakehead System Local

Toll. The Company also benefitted from stronger adjusted EBIT contributions from the United States Mid-Continent and Gulf Coast systems, mainly attributable to increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes and higher tariffs on Flanagan South Pipeline (Flanagan South).

Within the Gas Distribution segment, EGD adjusted EBIT increased for the first half of 2016 compared with the first half of 2015, primarily attributable to higher distribution charges arising from growth in EGD s rate base, customer growth and lower storage and transportation costs. In the second quarter of 2016, adjusted EBIT generated by EGD was lower compared with the corresponding 2015 period, primarily due to the relative timing and recognition of final rates approved by the Ontario Energy Board (OEB) for each of 2015 and 2016. In particular, the positive impact of the OEB s final rate determination for 2015 was reflected in the second quarter of that year, whereas the impact of the 2016 determination was reflected in the first quarter of 2016. The second quarter decrease in adjusted EBIT caused by these quarterly timing impacts was partially offset by higher distribution charges arising from growth in EGD s rate base and customer growth, and it is expected that adjusted EBIT at EGD for the full 2016 year will grow as a result of these factors.

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, higher throughput on certain Enbridge Offshore Pipelines (Offshore) and contributions from the Tupper Main and Tupper West gas plants (the Tupper Plants) following their acquisition on April 1, 2016. These positive effects were partially 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 delivered lower period-over-period adjusted EBIT as a result of weaker wind resources at certain facilities. Adjusted EBIT for the first half of 2016 was also negatively impacted by disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades.

Adjusted EBIT from Energy Services decreased for the three and six months ended June 30, 2016 as lower oil prices compressed crude oil location and quality differentials.

Adjusted Earnings

Adjusted earnings were $456 million, or $0.50 per common share, for the three months ended June 30, 2016 compared with $505 million, or $0.60 per common share, for the three months ended June 30, 2015. Adjusted earnings were $1,119 million, or $1.25 per common share, for the six months ended June 30, 2016 compared with $973 million, or $1.15 per common share, for the six months ended June 30, 2015.

The quarter-over-quarter decrease in adjusted earnings reflected the operating factors as discussed above in *Adjusted EBIT*. The impacts of the northeastern Alberta wildfires on adjusted earnings and adjusted earnings per share were approximately $26 million and $0.03, respectively. Adjusted earnings period-over-period were also impacted by the effects of interest expense, income taxes and noncontrolling interests as discussed below.

Interest expense for the three and six-month periods ended June 30, 2016 was higher compared with the corresponding 2015 periods resulting from 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 half of 2016 largely due to the period-over-period increase in earnings.

Adjusted earnings attributable to noncontrolling interests and redeemable noncontrolling interests decreased for the three and six months ended June 30, 2016 compared with the same periods in 2015. The redeemable noncontrolling interests in the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and its subsidiaries and investees) decreased mainly as a result of the quarter-over-quarter decrease in contributions from the Fund Group s Canadian liquids pipelines businesses reflecting the impacts of the northeastern Alberta wildfires in the second quarter of 2016 as discussed in *Impact of Wildfires in Northeastern Alberta*. Adjusted earnings attributable to noncontrolling interests in EEP decreased in the first half of 2016. Although EEP reflected higher contributions from its liquids pipelines businesses, there was a decrease in

EEP s overall period-over-period 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Depreciation and amortization[1]	**555**	485	**1,114**	959
Maintenance capital[2]	**(144)**	(164)	**(295)**	(316)
	1,500	1,370	**3,282**	2,723
Interest expense[3]	**(363)**	(291)	**(757)**	(584)
Current income taxes[3]	**(34)**	(50)	**(81)**	(76)
Preference share dividends	**(71)**	(71)	**(144)**	(142)
Distributions to noncontrolling interests	**(178)**	(166)	**(362)**	(324)
Distributions to redeemable noncontrolling interests	**(53)**	(26)	**(95)**	(53)
Cash distributions in excess of equity earnings[3]	**43**	80	**21**	126
Other non-cash adjustments	**24**	(38)	**118**	(60)
Available cash flow from operations (ACFFO)	**868**	808	**1,982**	1,610
1 Depreciation and amortization:				
Liquids Pipelines	***336***	*287*	***682***	*567*
Gas Distribution	***84***	*80*	***164***	*157*
Gas Pipelines and Processing	***75***	*68*	***149***	*133*
Green Power and Transmission	***47***	*46*	***95***	*92*
Energy Services	***1***	-	***1***	-
Eliminations and Other	***12***	*4*	***23***	*10*
	555	*485*	***1,114***	*959*
2 Maintenance capital:				
Liquids Pipelines	***(28)***	*(78)*	***(72)***	*(140)*
Gas Distribution	***(84)***	*(51)*	***(166)***	*(114)*
Gas Pipelines and Processing	***(12)***	*(8)*	***(23)***	*(15)*
Green Power and Transmission	***(1)***	-	***(1)***	-
Eliminations and Other	***(19)***	*(27)*	***(33)***	*(47)*
	(144)	*(164)*	***(295)***	*(316)*

3 These balances are presented net of adjusting items.

Available Cash Flow from Operations

ACFFO was $868 million for the three months ended June 30, 2016 compared with $808 million for the three months ended June 30, 2015. ACFFO was $1,982 million for the six months ended June 30, 2016 compared with $1,610 million for the six months ended June 30, 2015. The Company experienced strong period-over-period growth in ACFFO which was driven by the same factors as discussed in *Adjusted EBIT* above. However, the impacts of the northeastern Alberta wildfires negatively impacted period-over-period ACFFO by $74 million for the three and six months ended June 30, 2016.

Maintenance capital expenditures decreased period-over-period as higher expenditures in the Company s Gas Distribution and Gas Pipelines and Processing segments were more than 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 in 2016 over the full year as the Company continues to invest in its maintenance capital program to support the safety and reliability of its operations.

Partially offsetting the items discussed above, which created a period-over-period increase in ACFFO, was higher interest expense as discussed in *Adjusted Earnings* above.

Additionally, increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in the Fund Group partially offset other increases to ACFFO. Distributions were higher in the first half of 2016 compared with the first half of 2015 mainly as a result of increased public ownership in EEP and the Fund Group.

The ACFFO also includes cash distributions from the Company s equity investments. Equity earnings from such investments for the 2016 periods were higher compared with the corresponding periods of 2015; however, the cash distributions remained relatively stable period-over-period. Cash distributions were $182 million and $368 million for the three and six months ended June 30, 2016, respectively, compared with $189 million and $368 million of cash distributions received for the three and six months ended June 30, 2015.

NON-GAAP RECONCILIATION ACFFO

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Cash provided by operating activities - continuing operations	**1,370**	1,361	**3,231**	2,882
Adjusted for changes in operating assets and liabilities1	**(87)**	(105)	**(209)**	(252)
	1,283	1,256	**3,022**	2,630
Distributions to noncontrolling interests	**(178)**	(166)	**(362)**	(324)
Distributions to redeemable noncontrolling interests	**(53)**	(26)	**(95)**	(53)
Preference share dividends	**(71)**	(71)	**(144)**	(142)
Maintenance capital expenditures2	**(144)**	(164)	**(295)**	(316)
Significant adjusting items:				
Weather normalization	**(7)**	6	**6**	(27)
Project development and transaction costs	**3**	5	**3**	7
Realized inventory revaluation allowance3	**(15)**	(32)	**(283)**	(165)
Employee severance and restructuring costs	**8**	-	**8**	-
Other items	**42**	-	**122**	-
Available cash flow from operations (ACFFO)	**868**	808	**1,982**	1,610

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. This issuance was inclusive of 7.4 million common shares issued on exercise of the full amount of the underwriters over-allotment option. The proceeds were 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 will be used to fund 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, through its ownership of ENF and directly through investment in Fund Group entities, decreased from 89.3% to 86.9%. As at June 30, 2016, Enbridge s total economic interest in the Fund Group remained at 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 ongoing and no decision on any particular strategic alternative has been reached by EEP.

Enbridge has a large inventory of United States liquids 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

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 June 30, 2016, EEP s cumulative cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge). This includes a reduction of estimated remediation efforts offset by 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 June 30, 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.

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, other than fines and penalties, 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 June 30, 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 June 30, 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 includes 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.

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. Three 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.

Line 6B Fines and Penalties

As at June 30, 2016, included in EEP s total estimated costs related to the Line 6B crude oil release were US$69 million in fines and penalties. Of this amount, US$61 million relates to civil penalties under the Clean Water Act of the United States, which EEP fully accrued for.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan Southern Division (the Court) that is EEP s signed settlement agreement with the United States Environmental Protection Agency (EPA) and the United States Department of Justice regarding Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, EEP will pay US$62 million in civil penalties: US$61 million in respect of Line 6B and US$1 million in respect of Line 6A. The Consent Decree will take effect upon approval by the Court, following a comment period.

In addition to the monetary fines and penalties discussed above, the Consent Decree calls for replacement of Line 3, which EEP initiated in 2014 and is currently under regulatory review in the State of Minnesota as described in *Growth Projects Commercially Secured Projects Liquids Pipelines Line 3 Replacement Program United States Line 3 Replacement Program (EEP)*. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to EEP s comprehensive in-line inspection-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively these measures build on continuous improvements implemented since 2010 to EEP s leak detection program, control center operations and emergency response program. EEP estimates the total cost of these measures to be approximately US$110 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact the overall financial performance of EEP or the Company.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. In February 2014, the Federal Energy Regulatory Commission (FERC) rejected Seaway Pipeline s application but also set out a new methodology based on recent appellate court rulings 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 set the application for hearing. The case was assigned to an Administrative Law Judge (ALJ). The oral hearing with respect to the application began on July 7, 2016 and concluded on July 11, 2016. The ALJ will issue an 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.

Additionally, in a February 1, 2016 order, the FERC upheld Seaway Pipeline s current committed rate 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 PIPELINES AND PROCESSING

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) from the EPA for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable s Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it believed to be an exceedance of currently permitted limits for Volatile Organic Material. In April 2015, a second NFOV from the EPA was received in connection with this potential exceedance. Aux Sable engaged in discussions with the EPA to evaluate the impacts and ultimate resolution of these issues. On May 20, 2016, Aux Sable received a draft Consent Decree from the EPA and settlement discussions are expected to continue during the third quarter of 2016. The final settlement amount is not expected to be material.

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.

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GROWTH PROJECTS   COMMERCIALLY SECURED PROJECTS

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

(Canadian dollars, unless stated otherwise)		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
LIQUIDS PIPELINES					
1.	Eastern Access (EEP)[3]	US$0.3 billion	US$0.3 billion	2016	Complete
2.	JACOS Hangingstone Project (the Fund Group)	$0.2 billion	$0.1 billion	2017	Under construction
3.	Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$1.9 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	$1.3 billion	2019	Pre-construction
7.	U.S. Line 3 Replacement Program (EEP)	US$2.6 billion	US$0.4 billion	2019	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
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	$0.5 billion	$0.5 billion	2016	Acquisition completed
15.	Aux Sable Extraction Plant Expansion	US$0.1 billion	US$0.1 billion	2016	Substantially complete
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	US$0.1 billion	2016	Under construction
18.	Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.3 billion (£0.13 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 June 30, 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.

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 included 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 the Eastern Access initiative were completed between 2013 and 2015. The remaining component of the Eastern Access initiative involved a further upsizing of EEP s Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan increased capacity from 500,000 bpd to 570,000 bpd and included 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 was placed into service in June 2016 at a total cost of approximately US$0.3 billion.

The Eastern Access projects undertaken by EEP were 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, until the second quarter of 2016, Enbridge s capital funding contribution requirements to the Eastern Access projects were netted against its foregone cash distribution.

JACOS Hangingstone Project (the Fund Group)

The Company is undertaking the construction of facilities, which will provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). The project, which will provide capacity of 40,000 bpd, has been delayed at the shippers request and is now expected to enter service in the first quarter of 2017. The estimated cost of the project remains at approximately $0.2 billion, with expenditures to date of approximately $0.1 billion.

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 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, and 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 remaining work includes additional tankage which 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 addition, the expansion to increase the pipeline capacity to 1,200,000 bpd requires only the addition of pumping horsepower with no pipeline construction and is expected to cost approximately US$0.4 billion. In conjunction with shippers, a decision was made to delay the in-service date of this phase of the Southern Access expansion to 2019 to align more closely with the anticipated in-service date for the United States portion of the Line 3 Replacement Program (U.S. L3R Program) and Sandpiper. The expenditures incurred to date are 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, until the second quarter of 2016, Enbridge s capital funding contribution requirements to the Lakehead System Mainline Expansion were 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.

Several months prior to the National Energy Board (NEB) hearing held in 2015, 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 general terms of the settlement agreements were applied to all landowners directly impacted by the project, resulting in the resolution of nearly all outstanding landowner concerns. The NEB found these agreements and the resolution of outstanding concerns with nearly all potentially impacted landowners to be a persuasive factor in favour of the reasonableness of Enbridge s decommissioning plan.

In April 2016, the NEB found that the Canadian L3R Program is in the Canadian public interest and issued final conditions and a recommendation to the Federal Cabinet (the Cabinet) to issue a Certificate of Public Convenience and Necessity (the Certificate) for the construction and operation of the pipeline and related facilities. A decision by the Cabinet was expected to be issued three months following the NEB recommendation per legislation. However, because of the Federal Government s January 27, 2016 announcement that, outside of the NEB process it has directed Federal agencies to conduct an assessment of direct and upstream greenhouse gas (GHG) emissions and incremental consultation with affected communities and Indigenous peoples, the Minister of Natural Resources sought an extension of four months to the Government s legislated decision-making time limit (to seven months in total). As a result, Enbridge anticipates a decision from the Cabinet by the end of November 2016 and the issuance of the Certificate by the NEB in the days following the Cabinet decision.

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, which closed in May 2016 with six parties providing comments on the draft report. 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. On May 25, 2016, the Federal consultation process on the Canadian L3R Program was expanded with Natural Resources Canada undertaking consultations with Indigenous peoples impacted by the Canadian L3R Program and posting an online questionnaire to solicit input from interested and/or impacted parties. The results of these two efforts will be combined with the results of the GHG study and are expected to be presented to the Cabinet for deliberation in the fall of 2016 prior to the Cabinet making its decision on whether to approve the project.

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 $1.3 billion. With a delay in construction arising from a longer than anticipated permitting process, 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 (DOC) 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 DOC 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 concluded on May 13, 2016. The DOC is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. EEP now expects it to be issued in August 2016.

The ALJ who is overseeing the Line 3 Certificate of Need and Route Permit processes held a scheduling conference on May 16, 2016 at which the timeline for the scoping recommendation was discussed. A second pre-hearing conference has been scheduled for August 10, 2016 to further discuss the regulatory schedule.

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 DOC 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 and concluded on May 13, 2016. The DOC is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. EEP now expects it to be issued in August 2016.

The ALJ overseeing the Sandpiper Certificate of Need and Route Permit processes held a scheduling conference in June 2016 at which the DOC provided a draft EIS schedule. A second meeting will be held on August 10, 2016 to further discuss the regulatory schedule.

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 incurred to date 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 Plants and associated pipelines from a Canadian subsidiary of Murphy Oil Corporation 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 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 (22 miles) 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 (33 miles) 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 project has been announced by the Company, but has 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 (GIC) approved Northern Gateway, subject to 209 conditions following the recommendation from the Joint Review Panel (JRP). Nine applications to the Federal Court of Appeal (Federal Court) for leave for judicial review of the Order in Council approving the project 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. The decision of the Federal Court was released on June 30, 2016. The Federal Court found that for the most part the environmental review and Aboriginal consultation processes were reasonable, and the legal challenges to those aspects of the process were dismissed. However, the Federal Court found the Phase IV Crown consultation process was unacceptably flawed, and for that reason it quashed the Certificates of Public Convenience and Necessity (the Certificates) and sent the matter back to the GIC for redetermination.

The GIC options include redoing the Phase IV consultation, after which it can direct the NEB to issue the Certificates, direct the NEB to dismiss the application for the Certificates, or it can remit the matter back to the NEB for further consideration. The deadline for seeking Leave to Appeal to the Supreme Court of Canada is in late September 2016.

On July 8, 2016, the NEB informed Northern Gateway that in light of the Federal Court decision, it was suspending indefinitely its consideration of all filings related to the conditions attached to the Certificates.

The Company continues to work closely with its customers in advancing this project to open West Coast market access and also continues to build relationships and trust with communities and Aboriginal groups along the proposed route.

The Company previously 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 initial GIC 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 an Appeal to the Supreme Court of Canada, if any, 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Canadian Mainline	**177**	220	**486**	380
Lakehead System	**359**	259	**712**	533
Regional Oil Sands System	**88**	84	**181**	170
Mid-Continent and Gulf Coast	**160**	122	**341**	206
Southern Lights Pipeline	**39**	36	**80**	72
Bakken System	**54**	48	**108**	109
Feeder Pipelines and Other	**45**	40	**98**	70
Adjusted earnings before interest and income taxes	**922**	809	**2,006**	1,540
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(12)**	256	**556**	(574)
Canadian Mainline - Line 9B costs incurred during reversal	**-**	(1)	**-**	(2)
Lakehead System - changes in unrealized derivative fair value loss	**(4)**	(5)	**(5)**	(8)
Lakehead System - hydrostatic testing	**-**	-	**12**	-
Lakehead System - leak remediation costs	**(1)**	-	**(21)**	-
Regional Oil Sands System - northeastern Alberta wildfires pipelines and facilities restart costs	**(21)**	-	**(21)**	-
Regional Oil Sands System - leak insurance recoveries	**-**	-	**5**	12
Regional Oil Sands System - make-up rights adjustment	**(20)**	8	**(34)**	14
Regional Oil Sands System - leak remediation and long- term pipeline stabilization costs	**-**	(8)	**-**	(8)
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value loss	**(1)**	(3)	**(1)**	(4)
Mid-Continent and Gulf Coast - make-up rights adjustment	**(28)**	5	**(78)**	(5)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**(6)**	15	**26**	(33)
Bakken System - make-up rights adjustment	**3**	5	**-**	8
Bakken System - changes in unrealized derivative fair value loss	**(2)**	(3)	**(3)**	(4)
Feeder Pipelines and Other - investment impairment loss	**(176)**	-	**(176)**	-
Feeder Pipelines and Other - derecognition of regulatory balances	**(6)**	-	**(6)**	-
Feeder Pipelines and Other - gain on sale of non-core assets	**-**	22	**-**	22
Feeder Pipelines and Other - make-up rights adjustment	**(2)**	(3)	**(2)**	(5)
Feeder Pipelines and Other - project development costs	**(3)**	-	**(3)**	(1)
Earnings before interest and income taxes	**643**	1,097	**2,255**	952

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 2016 included recoveries in relation to hydrostatic testing performed on Line 2B in 2015.

- Lakehead System EBIT for 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 2016 and 2015 included insurance recoveries, as well as charges in 2015, 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.

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

Canadian Mainline

Canadian Mainline adjusted EBIT increased for the first half 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 half 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. Higher terminalling revenues also contributed to an increase in adjusted EBIT for the first half of 2016.

The positive effect of increased capacity on Canadian Mainline throughput discussed above was partially offset in the second quarter by the impact of extreme wildfires in northeastern Alberta. The wildfires resulted in a curtailment of production from oil sands facilities and certain of the Company s upstream pipelines and terminal facilities were temporarily shut down resulting in a disruption of service on Enbridge s Regional Oil Sands System with corresponding impacts on Enbridge s downstream pipelines deliveries, including the Canadian Mainline. The reduced system deliveries negatively impacted Canadian Mainline adjusted EBIT by approximately $30 million for the second quarter of 2016. For further details on the wildfires, refer to *Impact of Wildfires in Northeastern Alberta.*

Period-over-period growth in Canadian Mainline adjusted EBIT was also affected by a lower average Canadian Mainline IJT Residual Benchmark Toll. Effective April 1, 2016, Canadian Mainline IJT Residual Benchmark Toll decreased from US$1.63 to US$1.46, which more than offset the effects of the higher toll charged during the first quarter of 2016.

In addition, Canadian Mainline adjusted EBIT reflected the impact of a lower period-over-period exchange rate used to record the Canadian Mainline revenues. The IJT Benchmark Toll and its components are set in United States dollars and the majority of the Company s foreign exchange risk on Canadian Mainline revenue is hedged. For the three and six months ended June 30, 2016, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.034 and $1.076, respectively, compared with $1.097 and $1.088 for the corresponding 2015 periods.

Other factors which partially offset the increase in Canadian Mainline adjusted EBIT for the first half of the year included higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities.

The decrease in Canadian Mainline IJT Residual Benchmark Toll and lower exchange rate, together with the impact of the northeastern Alberta wildfires, resulted in a quarter-over-quarter decrease in Canadian Mainline adjusted EBIT.

In 2015, the Company commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $10 million and $22 million were recorded for the three and six months ended June 30, 2016, respectively (2015 - $8 million and $17 million), 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 and six months ended June 30, 2016 and 2015 is provided below:

June 30,	**2016**	2015
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.07**	$4.02
Lakehead System Local Toll[2]	**$2.61**	$2.39
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.46**	$1.63

1 The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2015, the IJT Benchmark Toll increased from US$4.02 to US$4.07. Effective July 1, 2016, this toll decreased to US$4.05.

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

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. Effective July 1, 2016, this toll increased to US$1.47.

Throughput Volume

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(thousands of bpd)				
Average throughput volume[1]	**2,242**	2,073	**2,392**	2,141

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 first half of 2016 compared with the first half of 2015. The period-over-period 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 half of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$279 million and US$535 million for the three and six months ended June 30, 2016, respectively, compared with US$211 million and US$433 million for the corresponding 2015 periods. The period-over-period increases 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 for the first half of 2016 also reflected increased downstream demand resulting from the completion of Southern Access Extension and the reversal and expansion of Line 9B. However, deliveries to the Lakehead System from the Canadian Mainline were lower during the second quarter, as a result of the northeastern Alberta wildfires. The reduced system deliveries negatively impacted Lakehead System adjusted EBIT by approximately $38 million for the three and six-month periods in

2016. Also partially offsetting the increase in adjusted EBIT for the first half of 2016 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 adjusted EBIT for the three and six months ended June 30, 2016 was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in 2016 due to the strengthening United States dollar versus the Canadian dollar. The Exchange Rate was $1.29 and $1.33 for the three and six months ended June 30, 2016, respectively, compared with $1.23 and $1.24 in the corresponding 2015 periods. 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(thousands of bpd)				
Average throughput volume1	**2,440**	2,208	**2,588**	2,269

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

Regional Oil Sands System

Regional Oil Sands System adjusted EBIT increased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. Higher adjusted EBIT primarily reflected contributions from assets placed into service in the second half of 2015, including the Sunday Creek Terminal and Woodland Pipeline Extension projects that were placed into service in the third quarter of 2015 and the AOC Hangingstone Lateral which was completed in December 2015. The increase in adjusted EBIT was partially offset by the effects of the wildfires in northeastern Alberta, as discussed under *Impact of Wildfires in Northeastern Alberta*, which negatively impacted Regional Oil Sands System adjusted EBIT by approximately $6 million for the second quarter of 2016.

Mid-Continent and Gulf Coast

Mid-Continent and Gulf Coast adjusted EBIT increased for the first half of 2016 compared with the corresponding 2015 period. The period-over-period 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 half 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$125 million and US$257 million for the three and six months ended June 30, 2016, respectively, compared with US$98 million and US$165 million for the corresponding 2015 periods. The increase in adjusted EBIT for the three and six-month periods primarily reflected increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes and higher tariffs on Flanagan South. Throughput on Flanagan South is affected by Canadian Mainline apportionment and the upstream apportionment experienced in the first half of 2015 was partially alleviated in 2016 with the expansion of the Company s mainline system completed in the third quarter of 2015.

As noted above, positively impacting period-over-period adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first half 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 for the first half of 2016 decreased slightly compared with the corresponding 2015 period. The period-over-period decrease in adjusted EBIT reflected lower rates and lower rail revenues 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 half of 2016 compared with the corresponding 2015 period. The decrease in adjusted EBIT was also partially offset by higher contributions from the Canadian portion of the Bakken System in the second quarter of 2016, primarily due to increased demand resulting from the enhanced downstream capacity on the mainline system. The higher contribution from the Canadian portion of the Bakken System was also a key driver for the quarter-over-quarter increase in Bakken System adjusted EBIT.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT from Bakken System s United States portion was US$36 million and US$73 million for the three and six months ended June 30, 2016, respectively, compared with US$35 million and US$82 million for the corresponding 2015 periods. The decrease in the first half of 2016 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 each of April 1, 2015 and 2016, as well as lower rail revenues related to EEP s Berthold rail facility. These negative impacts were 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 period-over-period adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first half 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 OtherFor further details refer to *Eliminations and Other*.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted EBIT increased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods, primarily reflecting new contributions from Southern Access Extension which was placed into service in the fourth quarter of 2015. These benefits were partially offset during the second quarter of 2016 by a decrease in adjusted EBIT from Eddystone Rail, primarily attributable to market conditions which impacted volumes at the rail facility, as well as lower contributions from Toledo resulting from refinery turnarounds which negatively impacted Toledo volumes.

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GAS DISTRIBUTION

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**72**	84	**247**	222
Noverco Inc. (Noverco)	**(5)**	5	**33**	36
Other Gas Distribution and Storage	**6**	7	**33**	36
Adjusted earnings before interest and income taxes	**73**	96	**313**	294
EGD - (warmer)/colder than normal weather	**9**	(8)	**(8)**	37
Noverco - changes in unrealized derivative fair value gains/(loss)	**1**	(10)	**-**	(14)
Noverco - recognition of regulatory balances	**-**	-	**17**	-
Earnings before interest and income taxes	**83**	78	**322**	317

Additional details on items impacting Gas Distribution EBIT include:

- Noverco EBIT for 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**72**	84	**247**	222
Interest expense	**(44)**	(37)	**(81)**	(75)
Income taxes	**-**	(3)	**(20)**	(30)
Adjusting items in respect of:				
Income taxes	**2**	(2)	**(2)**	10
Adjusted earnings	**30**	42	**144**	127
EGD - (warmer)/colder than normal weather	**7**	(6)	**(6)**	27
Earnings attributable to common shareholders	**37**	36	**138**	154

EGD adjusted earnings increased for the first half of 2016 compared with the first half of 2015, primarily attributable to higher distribution charges arising from growth in EGD s rate base, customer growth and lower storage and transportation costs. These positive effects were partially offset by lower transactional services revenues, mainly relating to pipeline optimization activities, and higher interest expense. For the second quarter of 2016, adjusted earnings generated by EGD were lower compared with the corresponding 2015 period, primarily due to the relative timing and recognition of final rates approved by the OEB for each of 2015 and 2016. In particular, the positive impact of the OEB s final rate determination for 2015 was reflected in the second quarter of that year, whereas the impact of the 2016 determination was reflected in the first quarter of 2016. The second quarter decrease in adjusted earnings caused by these quarterly timing impacts, as well as higher interest expense and higher earnings sharing expense, was partially offset by higher distribution charges arising from growth in EGD s rate base and customer growth.

Noverco

Noverco adjusted EBIT decreased for the three months ended June 30, 2016 compared with the corresponding 2015 period, primarily reflecting the timing of equity earnings adjustments between quarters. Excluding the impact of these adjustments, Noverco adjusted EBIT for the six months ended June 30, 2016 was comparable with the corresponding 2015 period.

GAS PIPELINES AND PROCESSING

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Aux Sable	**1**	2	**(2)**	8
Alliance Pipeline	**47**	37	**96**	77
Vector Pipeline	**6**	6	**15**	15
Canadian Midstream	**28**	19	**49**	40
Enbridge Offshore Pipelines (Offshore)	**8**	4	**21**	6
US Midstream	**4**	8	**6**	25
Other	**(4)**	(2)	**(8)**	(7)
Adjusted earnings before interest and income taxes	**90**	74	**177**	164
Aux Sable - accrual for commercial arrangements	**-**	(16)	**-**	(16)
Alliance Pipeline - derecognition of regulatory balances	**-**	8	**-**	8
Alliance Pipeline - changes in unrealized derivative fair value gains/(loss)	**-**	4	**12**	(8)
Offshore - gain on sale of non-core assets	**-**	6	**-**	6
US Midstream - goodwill impairment loss	**-**	(440)	**-**	(440)
US Midstream - assets impairment loss	**(11)**	(20)	**(11)**	(20)
US Midstream - changes in unrealized derivative fair value loss	**(59)**	(27)	**(97)**	(70)
US Midstream - make-up rights adjustment	**(1)**	-	**(1)**	1
Earnings/(loss) before interest and income taxes	**19**	(411)	**80**	(375)

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

- US Midstream EBIT for 2015 included a goodwill impairment charge related to the Company s United States natural gas and NGL businesses due to a prolonged decline in commodity prices which has reduced producers expected drilling programs and negatively impacted volumes on the Company s natural gas and NGL systems.

- US Midstream EBIT for 2016 reflected asset impairment charges in relation to certain non-core trucking assets that the Company is planning to sell.

- US Midstream EBIT for 2015 reflected asset impairment charges in relation to a non-core propylene pipeline asset, following finalization of a contract restructuring with the primary customer.

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

Aux Sable

Aux Sable adjusted EBIT decreased for the first half of 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, which represents EBIT from the Company s indirect 50% equity investment in Alliance Pipeline, increased for the three and six months ended June 30, 2016, compared with the corresponding 2015 periods, 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.

Canadian Midstream

Canadian Midstream adjusted EBIT increased for the three and six months ended June 30, 2016, compared with the three and six months ended June 30, 2015. The period-over-period increase reflected contributions from the Tupper Plants following their acquisition on April 1, 2016.

Offshore

Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT was US$6 million and US$16 million for the three and six months ended June 30, 2016, respectively, compared with US$3 million and US$5 million for the corresponding 2015 periods. The period-over-period increases 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 half 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$3 million and US$5 million for the three and six months ended June 30, 2016, respectively, compared with US$6 million and US$20 million for the corresponding 2015 periods. The period-over-period decreases 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 June 30, 2016, Enbridge s ownership interest in US Midstream, held through EEP, was 19.1% (December 31, 2015 - 19.2%).

GREEN POWER AND TRANSMISSION

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Green Power and Transmission	**40**	43	**88**	100
Adjusted earnings before interest and income taxes	**40**	43	**88**	100
Green Power and Transmission - changes in unrealized derivative fair value gains	**1**	-	**2**	2
Earnings before interest and income taxes	**41**	43	**90**	102

Green Power and Transmission adjusted EBIT decreased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. Green Power and Transmission reflected lower adjusted EBIT in the first half of 2016 as a result of weaker wind resources experienced at certain facilities, as well as disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades. Partially offsetting these negative impacts was a slight improvement in quarter-over-quarter solar resources at certain facilities.

ENERGY SERVICES

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Energy Services	**47**	78	**48**	106
Adjusted earnings before interest and income taxes	**47**	78	**48**	106
Energy Services - changes in unrealized derivative fair value loss	**(54)**	(11)	**(61)**	(42)
Earnings/(loss) before interest and income taxes	**(7)**	67	**(13)**	64

Additional details on items impacting Energy Services EBIT include:

- Energy Services earnings/(loss) before interest and income taxes for each period reflected changes in unrealized fair value loss 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 for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. The period-over-period decreases in adjusted EBIT reflected weaker performance from Energy Services Canadian and United States operations, partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first half of 2016. From its United States operations, adjusted EBIT for the three and six months ended June 30, 2016 was US$22 million and US$27 million, respectively, compared with US$56 million and US$68 million for the corresponding 2015 periods.

Adjusted EBIT decreased when compared with the first half of 2015 as low oil prices compressed crude oil location and quality differentials. Adjusted EBIT from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

ELIMINATIONS AND OTHER

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Operating and administrative	**(19)**	(11)	**(34)**	(28)
Realized foreign exchange derivative loss	**(64)**	(48)	**(151)**	(99)
Other	**-**	8	**16**	3
Adjusted loss before interest and income taxes	**(83)**	(51)	**(169)**	(124)

Changes in unrealized derivative fair value gains/(loss)	**38**	150	**405**	(287)
Unrealized intercompany foreign exchange gains/(loss)	**5**	(16)	**(55)**	55
Employee severance and restructuring costs	**(8)**	-	**(8)**	-
Drop down transaction costs	**-**	(18)	**-**	(20)
Earnings/(loss) before interest and income taxes	**(48)**	65	**173**	(376)

Eliminations and Other includes operating and administrative costs, and foreign exchange costs which are not allocated to business segments. Eliminations and Other also includes new business development activities and general corporate investments.

Included in Eliminations and Other adjusted loss before interest and income taxes for the three and six months ended June 30, 2016 was a realized loss of $64 million and $151 million, respectively, compared with $48 million and $99 million for the corresponding 2015 periods. The realized loss related to settlements under the Company s foreign exchange risk management program. The Company targets to hedge 80% or more of anticipated consolidated United States dollar denominated earnings from its United States operations utilizing foreign exchange derivative contracts with the objective of enhancing the predictability of its Canadian dollar earnings and ACFFO.

The notional amount of foreign currency derivatives realized during the three and six months ended June 30, 2016 was US$261 million and US$522 million, respectively, compared with US$238 million and US$476 million for the three and six months ended June 30, 2015. The average price to sell United States dollars for Canadian dollars for the three and six-month periods ended June 30, 2016 was $1.04, compared with $1.03 for the three and six-month periods ended June 30, 2015. The Exchange Rate for the three and six months ended June 30, 2016 was $1.29 and $1.33, compared with $1.23 and $1.24 for the three and six months ended June 30, 2015. As the hedged rate was lower than the Exchange Rate in each of the three and six-month periods in 2016 and 2015, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for both the three and six months ended June 30, 2016 was greater than the comparative 2015 periods due to a higher notional amount of derivatives and a greater unfavourable spread between the Exchange Rate and hedged rate. The realized loss in Eliminations and Other serves to partially offset the positive effect of translating the earnings performance of United States dollar denominated businesses at the Exchange Rate of $1.29 and $1.33 for the three and six months ended June 30, 2016 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 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 dollar denominated revenue are reported as part of the EBIT from Canadian Mainline.

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 *Recent Developments Common Share Issuances*, the Company and ENF have raised $2.3 billion and $0.6 billion, respectively, through public offerings since the beginning of 2016.

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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 June 30, 2016 and December 31, 2015.

					December 31, 2015
		June 30, 2016			
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge	2017-2020	**8,130**	**5,153**	**2,977**	6,988
Enbridge (U.S.) Inc.	2017	**4,202**	**643**	**3,559**	4,470
EEP	2018-2020	**3,382**	**2,659**	**723**	3,598
EGD	2017-2019	**1,017**	**548**	**469**	1,010
The Fund	2018	**1,500**	**411**	**1,089**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**26**	**-**	**26**	28
EPI	2017	**3,000**	**1,321**	**1,679**	3,000
Enbridge Southern Lights LP	2017	**5**	**-**	**5**	5
MEP	2018	**1,054**	**618**	**436**	1,121
Total committed credit facilities		**22,316**	**11,353**	**10,963**	21,720

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

During the three months ended June 30, 2016, the Company expanded its access to financial markets beyond North America to support its liquidity requirements on attractive terms. The Company established two term credit facilities with a syndicate of Asian banks providing the Company with access to US$968 million of incremental debt capital.

In addition to the committed credit facilities noted above, the Company also has $328 million (December 31, 2015 - $349 million) of uncommitted demand credit facilities, of which $81 million (December 31, 2015 - $185 million) were unutilized as at June 30, 2016.

The Company s net available liquidity of $11,658 million as at June 30, 2016 was inclusive of $1,257 million of unrestricted cash and cash equivalents and net of bank indebtedness of $562 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 June 30, 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 June 30, 2016, the Company s debt capitalization ratio was 62.7% compared with 65.5% as at December 31, 2015.

On June 27, 2016, Moody s Investor Services, Inc. (Moody s) confirmed the ratings of Enbridge (Baa2), the Fund (Baa2) and EEP (Baa3), but it changed their rating outlook from stable to negative. Moody s pointed to weaker financial credit metrics for a longer period due to project delays stemming from increased timelines associated with regulatory approvals. The typical timeline for resolution of a Moody s rating outlook is 12 to 18 months, but could be shorter or longer depending on the circumstances.

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

There are no material restrictions on the Company s cash with the exception of cash in trust of $17 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 Group. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

Excluding current maturities of long-term debt, the Company had a negative working capital position as at June 30, 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 June 30, 2016, the Company s net available liquidity totalled $11,658 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

The Company s cash flows from operating activities increased by $9 million and $349 million for the three and six months ended June 30, 2016, respectively, relative to the corresponding periods of 2015. The cash growth delivered by operations is a reflection of the positive operating factors discussed under *Adjusted EBIT* and *Adjusted Earnings*, which primarily include stronger contributions from the Liquids Pipelines segment, 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.

Changes in operating assets and liabilities were $64 million (2015 - $115 million) for the three months ended June 30, 2016 and $195 million (2015 - $272 million) for the six months ended June 30, 2016. Enbridge s operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, general variations in activity levels within the Company s businesses, as well as timing of cash receipts and payments.

INVESTING ACTIVITIES

Cash used in investing activities was $2,080 million and $3,932 million for the three and six months ended June 30, 2016 compared with $2,036 million and $3,913 million for the three and six months ended June 30, 2015. The increase in cash used during the first six months of 2016 over the comparative 2015 period was mainly due to an increase in cash spending on acquisitions and equity investments and an increase in loans issued to affiliates, which were offset largely by a decrease in cash spending on additions to property, plant and equipment.

During the first six months of 2016, the Company paid cash consideration of $539 million for the acquisition of the Tupper Plants, whereas in the first six months of 2015, the Company spent $106 million on the acquisition of a midstream business by EEP. In addition, during the second quarter of 2016, the Company made an initial equity investment in and issued an affiliate loan to acquire a 50% interest in a French offshore wind development company and to fund the Company s portion of ongoing development costs.

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 six months of 2016, additions to property, plant and equipment resulted in cash spending of $2,959 million compared with $3,563 million spent in the comparative 2015 period. This decrease in cash spending is due to the successful completion of growth projects in 2015, including the Edmonton to Hardisty Expansion, Southern Access

Extension and phases of the Eastern Access Program, which required significant capital spending during the first six months of 2015.

FINANCING ACTIVITIES

Net cash generated from financing activities was $230 million and $981 million for the three and six months ended June 30, 2016 compared with $686 million and $911 million for the three and six months ended June 30, 2015. The increase in cash provided during the first six months of 2016 over the comparative 2015 period was mainly due to proceeds from the Company s common share issuance in March 2016, partially offset by the repayment of short-term indebtedness, higher distributions to the public unitholders in the Company s sponsored vehicles and increased common share dividend payments to the Company s shareholders.

The proceeds from the Company s common share issuance were partly utilized to reduce the Company s credit facilities and commercial paper draws. The Company s overall debt decreased by $689 million during the first six months of 2016 compared with an overall increase of $1,290 million during the first six months of 2015.

The increase in common share dividend payments was attributable to the increase in the common share dividend rate effective March 2016 and higher number of common shares outstanding.

Common Share Issuances

On March 1, 2016, the Company completed the issuance of 56.5 million common shares for gross proceeds of approximately $2.3 billion. On April 20, 2016, ENF completed a public equity offering of 20.4 million common shares for gross proceeds of $575 million. Refer to *Recent Developments Common Share Issuances* for more details.

Dividend Reinvestment and Share Purchase Plan

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2016, dividends declared were $492 million (2015 - $399 million), of which $281 million (2015 - $238 million) were paid in cash and reflected in financing activities. The remaining $211 million (2015 - $161 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the six months ended June 30, 2016, dividends declared were $952 million (2015 - $795 million), of which $557 million (2015 - $479 million) were paid in cash and reflected in financing activities. The remaining $395 million (2015 - $316 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and six months ended June 30, 2016, 42.9% (2015 - 40.4%) and 41.5% (2015 - 39.7%) of total dividends declared were reinvested.

On July 26, 2016, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2016 to shareholders of record on August 15, 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 $1,839 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**2**	(15)	**(33)**	30
Interest rate contracts	**(428)**	392	**(1,004)**	(272)
Commodity contracts	**(18)**	(29)	**(2)**	(10)
Other contracts	**6**	(6)	**37**	(14)
Net investment hedges				
Foreign exchange contracts	**(12)**	22	**72**	(101)
	(450)	364	**(930)**	(367)
Amount of (gains)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(1)**	6	**2**	6
Interest rate contracts[2]	**72**	23	**51**	33
Commodity contracts[3]	**2**	(2)	**(6)**	(22)
Other contracts[4]	**(4)**	1	**(30)**	6
	69	28	**17**	23
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**5**	(12)	**31**	(35)
Commodity contracts[3]	**-**	-	**-**	5
	5	(12)	**31**	(30)
Amount of gains/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**28**	388	**1,044**	(905)
Interest rate contracts[2]	**4**	-	**8**	-
Commodity contracts[3]	**(114)**	(35)	**(298)**	(227)
Other contracts[4]	**5**	(1)	**11**	1
	(77)	352	**765**	(1,131)

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 and maintains substantial capacity under its committed bank lines of credit, as discussed under *Liquidity and Capital Resources,* to address any contingencies. The Company also maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at June 30, 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, netting arrangements and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools. 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.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for Credit Losses

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

QUARTERLY FINANCIAL INFORMATION

	2016			2015			2014	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(millions of Canadian dollars, except per share amounts)								
Revenues	**7,939**	8,795	8,914	8,320	8,631	7,929	8,797	8,297
Earnings/(loss) attributable to common shareholders	**301**	1,213	378	(609)	577	(383)	88	(80)
Earnings/(loss) per common share	**0.33**	1.38	0.44	(0.72)	0.68	(0.46)	0.11	(0.10)
Diluted earnings/(loss) per common share	**0.33**	1.38	0.44	(0.72)	0.67	(0.46)	0.10	(0.10)
Dividends per common share	**0.530**	0.530	0.465	0.465	0.465	0.465	0.350	0.350
EGD - warmer/(colder) than normal weather	**(7)**	13	16	-	6	(33)	(1)	2
Changes in unrealized derivative fair value (gains)/loss	**1**	(652)	45	654	(296)	977	164	396

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

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

- 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 and fourth quarters of 2015, respectively, and $4 million was recognized in each of the second and fourth quarters of 2014. 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 transfer of Enbridge s Canadian Liquids Pipelines business and certain Canadian renewable energy assets to EIPLP in which the Fund has an indirect interest, resulting in a $247 million loss on the de-designation of interest rate hedges, an $88 million write-off of a regulatory asset in respect of taxes and $16 million of transaction costs.

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

- 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)	934,229,449
Stock Options - issued and outstanding (22,681,361 vested)	38,446,399

1 Outstanding share data information is provided as at July 15, 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)

June 30, 2016

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**5,470**	5,975	**10,274**	11,206
Gas distribution sales	**504**	528	**1,511**	2,119
Transportation and other services	**1,965**	2,128	**4,949**	3,235
	7,939	8,631	**16,734**	16,560
Expenses				
Commodity costs	**5,303**	5,799	**10,014**	10,841
Gas distribution costs	**284**	300	**1,038**	1,664
Operating and administrative	**1,003**	928	**2,083**	1,919
Depreciation and amortization	**555**	485	**1,114**	959
Environmental costs, net of recoveries	**-**	7	**17**	(4)
Goodwill impairment	**-**	440	**-**	440
	7,145	7,959	**14,266**	15,819
	794	672	**2,468**	741
Income/(loss) from equity investments *(Note 6)*	**(37)**	109	**189**	242
Other income/(expense)	**(26)**	158	**250**	(299)
Interest expense	**(369)**	(284)	**(781)**	(535)
	362	655	**2,126**	149
Income taxes recovery/(expense) *(Note 13)*	**(10)**	(232)	**(427)**	53
Earnings	**352**	423	**1,699**	202
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	224	**(41)**	134
Earnings attributable to Enbridge Inc.	**372**	647	**1,658**	336
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Earnings attributable to Enbridge Inc. common shareholders	**301**	577	**1,514**	194
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 10)*	**0.33**	0.68	**1.69**	0.23
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 10)*	**0.33**	0.67	**1.67**	0.23

See accompanying notes to the unaudited interim consolidated financial statements.

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(unaudited; millions of Canadian dollars)				
Earnings	**352**	423	**1,699**	202
Other comprehensive income/(loss), net of tax				
Change in unrealized gains/(loss) on cash flow hedges	**(234)**	285	**(677)**	(220)
Change in unrealized gains/(loss) on net investment hedges	**(23)**	80	**371**	(346)
Other comprehensive income/(loss) from equity investees	**1**	13	**(1)**	22
Reclassification to earnings of realized cash flow hedges	**21**	19	**11**	10
Reclassification to earnings of unrealized cash flow hedges	**5**	(6)	**14**	(36)
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**7**	9	**9**	13
Change in foreign currency translation adjustment	**61**	(304)	**(1,316)**	1,293
Other comprehensive income/(loss), net of tax	**(162)**	96	**(1,589)**	736
Comprehensive income	**190**	519	**110**	938
Comprehensive loss attributable to noncontrolling interests and redeemable noncontrolling interests	**70**	171	**170**	46
Comprehensive income attributable to Enbridge Inc.	**260**	690	**280**	984
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Comprehensive income attributable to Enbridge Inc. common shareholders	**189**	620	**136**	842

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Six months ended June 30,	
	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	**395**	316
Shares issued on exercise of stock options	**25**	54
Balance at end of period	**10,052**	7,039
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	**30**	23
Options exercised	**(12)**	(14)
Dilution gains and other	**98**	34
Balance at end of period	**3,417**	2,810
Retained earnings		
Balance at beginning of period	**142**	1,571
Earnings attributable to Enbridge Inc.	**1,658**	336
Preference share dividends	**(144)**	(142)
Common share dividends declared	**(952)**	(795)
Dividends paid to reciprocal shareholder	**13**	11
Redemption value adjustment attributable to redeemable noncontrolling interests	**(604)**	312
Adjustment relating to equity method investment	**(30)**	-
Balance at end of period	**83**	1,293
Accumulated other comprehensive income/(loss) *(Note 11)*		
Balance at beginning of period	**1,632**	(435)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(1,378)**	648
Balance at end of period	**254**	213
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	**20,219**	17,787
Noncontrolling interests		
Balance at beginning of period	**1,300**	2,015
Earnings/(loss) attributable to noncontrolling interests	**22**	(149)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	**(146)**	(16)
Change in foreign currency translation adjustment	**(55)**	123
Reclassification to earnings of realized cash flow hedges	**13**	(9)
Reclassification to earnings of unrealized cash flow hedges	**3**	(26)
	(185)	72
Comprehensive loss attributable to noncontrolling interests	**(163)**	(77)
Distributions	**(362)**	(324)
Contributions	**28**	579
Drop down of interest to Enbridge Energy Partners, L.P.	**-**	(304)
Dilution loss	**-**	(53)
Other	**(6)**	(5)
Balance at end of period	**797**	1,831
Total equity	**21,016**	19,618
Dividends paid per common share	**1.06**	0.93

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended		Six months ended	
	June 30,		June 30,	
	2016	2015	**2016**	2015
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**352**	423	**1,699**	202
Depreciation and amortization	**555**	485	**1,114**	959
Deferred income taxes (recovery)/expense	**(26)**	183	**348**	(139)
Changes in unrealized (gains)/loss on derivative instruments, net *(Note 12)*	**77**	(352)	**(765)**	1,131
Cash distributions in excess of equity earnings	**43**	80	**3**	126
Impairment *(Note 6)*	**187**	456	**187**	456
Gain on disposition	**-**	(29)	**-**	(34)
Hedge ineffectiveness *(Note 12)*	**5**	(12)	**31**	(30)
Inventory revaluation allowance	**10**	2	**178**	45
Unrealized (gains)/loss on intercompany loan	**(5)**	16	**55**	(55)
Other	**85**	4	**172**	(31)
Changes in environmental liabilities, net of recoveries	**23**	(10)	**14**	(20)
Changes in operating assets and liabilities	**64**	115	**195**	272
	1,370	1,361	**3,231**	2,882
Investing activities				
Additions to property, plant and equipment	**(1,314)**	(1,973)	**(2,959)**	(3,563)
Joint venture financing	**5**	-	**(5)**	-
Long-term investments	**(114)**	(37)	**(247)**	(179)
Restricted long-term investments	**(16)**	(11)	**(28)**	(22)
Additions to intangible assets	**(29)**	(43)	**(56)**	(62)
Acquisition *(Note 4)*	**(485)**	-	**(539)**	(106)
Proceeds from disposition	**-**	34	**-**	34
Affiliate loans, net	**(117)**	3	**(115)**	6
Changes in restricted cash	**(10)**	(9)	**17**	(21)
	(2,080)	(2,036)	**(3,932)**	(3,913)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**(103)**	(95)	**140**	(551)
Net change in commercial paper and credit facility draws	**758**	1,215	**(406)**	2,236
Debenture and term note repayments	**(423)**	(19)	**(423)**	(395)
Contributions from noncontrolling interests	**12**	54	**28**	579
Distributions to noncontrolling interests	**(178)**	(166)	**(362)**	(324)
Contributions from redeemable noncontrolling interests	**563**	-	**567**	-
Distributions to redeemable noncontrolling interests	**(53)**	(26)	**(95)**	(53)
Common shares issued	**6**	32	**2,233**	40
Preference share dividends	**(71)**	(71)	**(144)**	(142)
Common share dividends	**(281)**	(238)	**(557)**	(479)
	230	686	**981**	911
Effect of translation of foreign denominated cash and cash equivalents	**2**	7	**(38)**	68
Increase/(decrease) in cash and cash equivalents	**(478)**	18	**242**	(52)
Cash and cash equivalents at beginning of period	**1,735**	1,191	**1,015**	1,261
Cash and cash equivalents at end of period	**1,257**	1,209	**1,257**	1,209

See accompanying notes to the unaudited interim consolidated financial statements.

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CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2016	December 31, 2015
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,257**	1,015
Restricted cash	**17**	34
Accounts receivable and other *(Note 5)*	**4,526**	5,430
Accounts receivable from affiliates	**7**	7
Inventory	**1,002**	1,111
	6,809	7,597
Property, plant and equipment, net	**64,111**	64,434
Long-term investments	**6,697**	7,008
Restricted long-term investments	**77**	49
Deferred amounts and other assets	**3,220**	3,160
Intangible assets, net	**1,556**	1,348
Goodwill	**77**	80
Deferred income taxes	**1,051**	839
	83,598	84,515
Liabilities and equity		
Current liabilities		
Bank indebtedness	**562**	361
Short-term borrowings	**538**	599
Accounts payable and other	**6,828**	7,351
Accounts payable to affiliates	**84**	48
Interest payable	**313**	324
Environmental liabilities	**158**	141
Current maturities of long-term debt *(Note 9)*	**5,105**	1,990
	13,588	10,814
Long-term debt *(Note 9)*	**34,298**	39,391
Other long-term liabilities	**5,749**	6,056
Deferred income taxes	**5,834**	5,915
	59,469	62,176
Commitments and contingencies *(Note 15)*		
Redeemable noncontrolling interests	**3,113**	2,141
Equity		
Share capital *(Note 10)*		
Preference shares	**6,515**	6,515
Common shares (934 and 868 outstanding at June 30, 2016 and December 31, 2015, respectively)	**10,052**	7,391
Additional paid-in capital	**3,417**	3,301
Retained earnings	**83**	142
Accumulated other comprehensive income *(Note 11)*	**254**	1,632
Reciprocal shareholding	**(102)**	(83)
Total Enbridge Inc. shareholders equity	**20,219**	18,898
Noncontrolling interests	**797**	1,300

	21,016	20,198
	83,598	84,515

Variable Interest Entities (Note 8)

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 June 30, 2016 and results of operations and cash flows for the three and six month s ended June 30, 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., 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 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.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for Credit Losses

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

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; and

- 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 and six months ended June 30, 2016 and 2015 are as follows:

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

Loss attributable to noncontrolling interests and redeemable noncontrolling interests							**20**
Preference share dividends							**(71)**
Earnings attributable to Enbridge Inc. common shareholders							**301**
Additions to property, plant and equipment1	**1,070**	**144**	**81**	**10**	**-**	**10**	**1,315**

Three months ended June 30, 2015 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
Revenues	1,838	626	1,006	123	5,167	(129)	8,631
Commodity and gas distribution costs	(3)	(328)	(829)	1	(5,075)	135	(6,099)
Operating and administrative	(564)	(135)	(140)	(35)	(24)	(30)	(928)
Depreciation and amortization	(287)	(80)	(68)	(46)	-	(4)	(485)
Environmental costs, net of recoveries	(7)	-	-	-	-	-	(7)
Goodwill impairment	-	-	(440)	-	-	-	(440)
	977	83	(471)	43	68	(28)	672
Income/(loss) from equity investments	85	(17)	46	(1)	(3)	(1)	109
Other income	35	12	14	1	2	94	158
Earnings/(loss) before interest and income taxes	1,097	78	(411)	43	67	65	939
Interest expense							(284)
Income taxes							(232)
Earnings							423
Loss attributable to noncontrolling interests and redeemable noncontrolling interests							224
Preference share dividends							(70)
Earnings attributable to Enbridge Inc. common shareholders							577
Additions to property, plant and equipment1	1,619	229	87	8	-	31	1,974

Six months ended June 30, 2016 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
Revenues	**4,356**	**1,779**	**1,267**	**256**	**9,244**	**(168)**	**16,734**
Commodity and gas distribution costs	**(5)**	**(1,059)**	**(946)**	**3**	**(9,213)**	**168**	**(11,052)**
Operating and administrative	**(1,429)**	**(278)**	**(246)**	**(77)**	**(34)**	**(19)**	**(2,083)**
Depreciation and amortization	**(682)**	**(164)**	**(149)**	**(95)**	**(1)**	**(23)**	**(1,114)**
Environmental costs, net of recoveries	**(17)**	**-**	**-**	**-**	**-**	**-**	**(17)**
	2,223	**278**	**(74)**	**87**	**(4)**	**(42)**	**2,468**
Income/(loss) from equity investments	**30**	**27**	**134**	**1**	**(3)**	**-**	**189**
Other income/(expense)	**2**	**17**	**20**	**2**	**(6)**	**215**	**250**
Earnings/(loss) before interest and income taxes	**2,255**	**322**	**80**	**90**	**(13)**	**173**	**2,907**
Interest expense							**(781)**
Income taxes							**(427)**
Earnings							**1,699**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							**(41)**
Preference share dividends							**(144)**
Earnings attributable to Enbridge Inc. common shareholders							**1,514**
Additions to property, plant and equipment1	**2,402**	**392**	**133**	**17**	**-**	**16**	**2,960**

Six months ended June 30, 2015 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
Revenues	2,629	2,418	2,133	254	9,374	(248)	16,560
Commodity and gas distribution costs	(4)	(1,696)	(1,794)	2	(9,265)	252	(12,505)
Operating and administrative	(1,245)	(269)	(255)	(64)	(42)	(44)	(1,919)
Depreciation and amortization	(567)	(157)	(133)	(92)	-	(10)	(959)
Environmental costs, net of recoveries	4	-	-	-	-	-	4
Goodwill impairment	-	-	(440)	-	-	-	(440)
	817	296	(489)	100	67	(50)	741
Income/(loss) from equity investments	145	(3)	108	-	(5)	(3)	242
Other income/(expense)	(10)	24	6	2	2	(323)	(299)
Earnings/(loss) before interest and income taxes	952	317	(375)	102	64	(376)	684
Interest expense							(535)
Income taxes recovery							53
Earnings							202
Loss attributable to noncontrolling interests and redeemable noncontrolling interests							134
Preference share dividends							(142)
Earnings attributable to Enbridge Inc. common shareholders							194
Additions to property, plant and equipment[1]	2,941	335	206	37	-	45	3,564

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

OUT-OF-PERIOD ADJUSTMENT

Earnings attributable to Enbridge Inc. common shareholders for the six months ended June 30, 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

(millions of Canadian dollars)	**June 30, 2016**	December 31, 2015
Liquids Pipelines	**52,040**	52,015
Gas Distribution	**9,596**	9,901
Gas Pipelines and Processing	**11,292**	11,559
Green Power and Transmission	**4,946**	4,977
Energy Services	**1,990**	1,889
Eliminations and Other	**3,734**	4,174
	83,598	84,515

4. ACQUISITION

On April 1, 2016, Enbridge acquired the Tupper Main and Tupper West gas plants and associated pipelines (the Tupper Plants) located in northeastern British Columbia for cash consideration of $539 million. The purchase price for the Tupper Plants was equal to the fair value of identifiable net assets acquired and accordingly, the Company did not recognize any goodwill as part of the acquisition. Transaction costs incurred by the Company totalled approximately $1 million and are included in Operating and administrative expense within the Consolidated Statements of Earnings. The Tupper Plants are included within the Gas Pipelines and Processing segment.

Since the closing date through June 30, 2016, the Tupper Plants have generated approximately $10 million in revenue and $7 million in earnings before interest and income taxes. If the acquisition had closed on January 1, 2016, the Consolidated Statements of Earnings would have shown revenue and earnings before interest and income taxes of $21 million and $13 million respectively.

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

April 1,	**2016**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	288
Intangible assets	251
	539
Purchase price:	
Cash	539

The purchase price allocation was prepared on a preliminary basis and is subject to change as additional information becomes available concerning the fair value and tax basis of the assets acquired. Any additional adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain 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 was amended in June 2016 to extend the termination date that provides for purchases to occur on a monthly basis through to December 2019, 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$239 million ($311 million) and US$317 million ($439 million) as at June 30, 2016 and December 31, 2015, respectively.

6. LONG-TERM INVESTMENTS

EOLIEN MARITIME FRANCE SAS

Effective May 19, 2016, Enbridge acquired a 50% interest in Eolien Maritime France SAS (EMF), a French offshore wind development company. EMF is co-owned by Enbridge and EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind farms off the coast of France, which are currently under development. Enbridge s portion of the costs incurred to date is approximately $181 million (128 million) with $60 million presented in Long-term investments, and $121 million presented in Deferred amounts and other assets.

EDDYSTONE RAIL COMPANY, LLC

During the three months ended June 30, 2016, the Company recorded an investment impairment of $176 million related to Enbridge s 75% joint venture interest in Eddystone Rail Company, LLC (Eddystone Rail), which is held through Enbridge Rail (Philadelphia) L.L.C., a wholly-owned subsidiary. Eddystone Rail is a rail-to-barge transloading facility located in the greater Philadelphia, Pennsylvania area that delivers Bakken and other light sweet crude oil to Philadelphia area refineries. Due to a significant decrease in price spreads between Bakken crude oil and West Africa/Brent crude oil and increased competition in the region, demand for Eddystone Rail services dropped significantly, which led to the completion of an impairment test. The impairment charge is presented within Income/(loss) from equity investments on the Consolidated Statements of Earnings. The investment in Eddystone Rail is included within the Liquids Pipelines segment.

The impairment charge was based on the amount by which the carrying value of the asset exceeded fair value, determined using an adjusted net worth approach. The Company s estimate of fair value required it to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of Eddystone Rail.

7. GOODWILL

During the quarter ended June 30, 2015, the Company recorded an impairment charge of $440 million ($167 million after-tax attributable to Enbridge) related to EEP s natural gas and NGL businesses, which EEP holds directly and indirectly through its partially-owned subsidiary, Midcoast Energy Partners, L.P. Due to a prolonged decline in commodity prices, reduction in producers expected drilling programs have negatively impacted forecasted cash flows from EEP s natural gas and NGL systems. This change in circumstance led to the completion of an impairment test, resulting in a full impairment of goodwill on EEP s natural gas and NGL businesses.

In performing the impairment assessment, EEP measured the fair value of its reporting units primarily by using a discounted cash flow analysis and it also considered overall market capitalization of its business, cash flow measurement data and other factors. EEP s estimate of fair value required it to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of its reporting units.

8. 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 35.5% 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 an indirect wholly-owned subsidiary of 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 54.0% 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 June 30, 2016, the Company s economic interest in EIPLP was 79.1%.

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.

June 30,	**2016**
(millions of Canadian dollars)	
Cash and cash equivalents	**417**
Restricted cash	**3**
Accounts receivable and other	**797**
Accounts receivable from affiliates	**3**
Inventory	**74**
	1,294
Property, plant and equipment, net	**44,569**
Long-term investments	**959**
Restricted long-term investments	**71**
Deferred amounts and other assets	**1,799**
Intangible assets, net	**456**
Goodwill	**29**
Deferred income taxes	**240**
	49,417
Bank indebtedness	**(127)**
Accounts payable and other	**(1,452)**
Accounts payable to affiliates	**(66)**
Interest payable	**(172)**
Environmental liabilities	**(155)**
Current maturities of long-term debt	**(406)**

	(2,378)
Long-term debt	**(16,228)**
Other long-term liabilities	**(1,402)**
Deferred income taxes	**(1,430)**
	(21,438)
Net assets before noncontrolling interests	**27,979**

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., 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 Variable Interest Entities

Enbridge Income 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 June 30, 2016 is presented below.

June 30, 2016	Carrying Amount of Investment in VIE	Enbridge s Maximum Exposure to Loss
(millions of Canadian dollars)		
Vector Pipeline L.P.[1]	**147**	**147**
Aux Sable Liquid Products L.P.[1]	**185**	**185**
Rampion Offshore Wind Limited[2]	**274**	**457**
Eddystone Rail Company, LLC[3]	**18**	**23**
Illinois Extension Pipeline Company, L.L.C.[1]	**744**	**744**
Eolien Maritime France SAS[4]	**60**	**679**
Other[1]	**17**	**17**
	1,445	**2,252**

1 At June 30, 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 June 30, 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 June 30, 2016, the maximum exposure to loss includes the carrying value of an outstanding loan issued by the Company.

4 At June 30, 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 and an outstanding affiliate loan receivable for $121 million held by the Company (Note 6).

The Company does not have an obligation to and did not provide any additional financial support to the VIEs during the period ended June 30, 2016.

9. DEBT

The following table provides details of the Company s committed credit facilities as at June 30, 2016 and December 31, 2015.

		June 30, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws1	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Inc.	2017-2020	**8,130**	**5,153**	**2,977**	6,988
Enbridge (U.S.) Inc.	2017	**4,202**	**643**	**3,559**	4,470
Enbridge Energy Partners, L.P.	2018-2020	**3,382**	**2,659**	**723**	3,598
Enbridge Gas Distribution Inc.	2017-2019	**1,017**	**548**	**469**	1,010
Enbridge Income Fund	2018	**1,500**	**411**	**1,089**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**26**	-	**26**	28
Enbridge Pipelines Inc.	2017	**3,000**	**1,321**	**1,679**	3,000
Enbridge Southern Lights LP	2017	**5**	-	**5**	5
Midcoast Energy Partners, L.P.	2018	**1,054**	**618**	**436**	1,121
Total committed credit facilities		**22,316**	**11,353**	**10,963**	21,720

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

During the six months ended June 30, 2016, the Company entered into a three year, extendible credit facility for US$650 million with a syndicate of Chinese banks. The Company also entered into a three year, extendible credit facility for ¥32,622 million (US$318 million) with a syndicate of Japanese banks.

In addition to the committed credit facilities noted above, the Company also has $328 million (December 31, 2015 - $349 million) of uncommitted demand credit facilities, of which $81 million (December 31, 2015 - $185 million) was unutilized as at June 30, 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.

As at June 30, 2016, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $9,127 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.

10. SHARE CAPITAL

COMMON SHARES

June 30,	**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	**8**	**395**	5	316
Shares issued on exercise of stock options	**2**	**25**	3	54
Balance at end of period	**934**	**10,052**	860	7,039

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 13 million (2015 -12 million) for the three and six months ended June 30, 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(number of shares in millions)				
Weighted average shares outstanding	**917**	846	**897**	843
Effect of dilutive options	**8**	12	**7**	13
Diluted weighted average shares outstanding	**925**	858	**904**	856

For the three and six months ended June 30, 2016, 7,802,601 and 13,976,687 anti-dilutive stock options (2015 - 5,851,770) with a weighted average exercise price of $55.77 and $51.34 (2015 - $59.14) were excluded from the diluted earnings per common share calculation.

11. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income/(loss) (AOCI) attributable to Enbridge Inc. common shareholders for the six months ended June 30, 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	**(711)**	**384**	**(1,253)**	**(7)**	**-**	**(1,587)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	**52**	**-**	**-**	**-**	**-**	**52**
Commodity contracts2	**(5)**	**-**	**-**	**-**	**-**	**(5)**
Foreign exchange contracts3	**1**	**-**	**-**	**-**	**-**	**1**
Other contracts4	**(31)**	**-**	**-**	**-**	**-**	**(31)**
Amortization of pension and OPEB actuarial loss5	**-**	**-**	**-**	**-**	**13**	**13**
	(694)	**384**	**(1,253)**	**(7)**	**13**	**(1,557)**

Tax impact						
Income tax on amounts retained in AOCI	**200**	**(13)**	**-**	**6**	**-**	**193**
Income tax on amounts reclassified to earnings	**(10)**	**-**	**-**	**-**	**(4)**	**(14)**
	190	**(13)**	**-**	**6**	**(4)**	**179**
Balance at June 30, 2016	**(1,192)**	**(424)**	**2,112**	**36**	**(278)**	**254**

	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	(272)	(370)	1,149	24	-	531
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts1	8	-	-	-	-	8
Commodity contracts2	(4)	-	-	-	-	(4)
Foreign exchange contracts3	7	-	-	-	-	7
Other contracts4	6	-	-	-	-	6
Amortization of pension and OPEB actuarial loss5	-	-	-	-	17	17
	(255)	(370)	1,149	24	17	565
Tax impact						
Income tax on amounts retained in AOCI	73	24	-	(2)	-	95
Income tax on amounts reclassified to earnings	(8)	-	-	-	(4)	(12)
	65	24	-	(2)	(4)	83
Balance at June 30, 2015	(678)	(238)	1,458	17	(346)	213

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.*

12. 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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

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

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 June 30, 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.

June 30, 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	**86**	**3**	**8**	**97**	**(47)**	**50**
Interest rate contracts	**1**	**-**	**-**	**1**	**(1)**	**-**
Commodity contracts	**7**	**-**	**499**	**506**	**(95)**	**411**
Other contracts	**-**	**-**	**3**	**3**	**(1)**	**2**
	94	**3**	**510**	**607**	**(144)**	**463**
Deferred amounts and other assets						
Foreign exchange contracts	**2**	**5**	**83**	**90**	**(80)**	**10**
Commodity contracts	**-**	**-**	**116**	**116**	**(21)**	**95**
	2	**5**	**199**	**206**	**(101)**	**105**
Accounts payable and other						
Foreign exchange contracts	**-**	**(150)**	**(604)**	**(754)**	**47**	**(707)**
Interest rate contracts	**(759)**	**-**	**(187)**	**(946)**	**1**	**(945)**
Commodity contracts	**-**	**-**	**(477)**	**(477)**	**95**	**(382)**
Other contracts	**-**	**-**	**(1)**	**(1)**	**1**	**-**
	(759)	**(150)**	**(1,269)**	**(2,178)**	**144**	**(2,034)**
Other long-term liabilities						
Foreign exchange contracts	**-**	**(138)**	**(1,992)**	**(2,130)**	**80**	**(2,050)**
Interest rate contracts	**(959)**	**-**	**(214)**	**(1,173)**	**-**	**(1,173)**
Commodity contracts	**(1)**	**-**	**(205)**	**(206)**	**21**	**(185)**
Other contracts	**(3)**	**-**	**(2)**	**(5)**	**-**	**(5)**
	(963)	**(138)**	**(2,413)**	**(3,514)**	**101**	**(3,413)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**88**	**(280)**	**(2,505)**	**(2,697)**	**-**	**(2,697)**
Interest rate contracts	**(1,717)**	**-**	**(401)**	**(2,118)**	**-**	**(2,118)**
Commodity contracts	**6**	**-**	**(67)**	**(61)**	**-**	**(61)**
Other contracts	**(3)**	**-**	**-**	**(3)**	**-**	**(3)**
	(1,626)	**(280)**	**(2,973)**	**(4,879)**	**-**	**(4,879)**

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.

June 30, 2016	2016	2017	2018	2019	2020	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**473**	**413**	**2**	**2**	**2**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,134**	**3,395**	**2,756**	**2,943**	**2,722**	**787**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**26**	**77**	**6**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**-**	**89**	**25**	**144**
	-	**-**	**-**	**32,662**	**-**	**-**

Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*						
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**4,207**	**7,343**	**4,352**	**1,497**	**149**	**394**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,183**	**3,282**	**1,906**	**763**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**49**	**48**	**40**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(76)**	**(87)**	**(33)**	**(7)**	**(6)**	**(6)**
Commodity contracts - crude oil *(millions of barrels)*	**(1)**	**(19)**	**(9)**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(5)**	**-**	**-**	**-**	**-**	**-**
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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**2**	(15)	**(33)**	30
Interest rate contracts	**(428)**	392	**(1,004)**	(272)
Commodity contracts	**(18)**	(29)	**(2)**	(10)
Other contracts	**6**	(6)	**37**	(14)
Net investment hedges				
Foreign exchange contracts	**(12)**	22	**72**	(101)
	(450)	364	**(930)**	(367)
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts1	**(1)**	6	**2**	6
Interest rate contracts2	**72**	23	**51**	33
Commodity contracts3	**2**	(2)	**(6)**	(22)
Other contracts4	**(4)**	1	**(30)**	6
	69	28	**17**	23
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts2	**5**	(12)	**31**	(35)
Commodity contracts3	**-**	-	**-**	5
	5	(12)	**31**	(30)

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 $33 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 42 months as at June 30, 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**28**	388	**1,044**	(905)
Interest rate contracts[2]	**4**	-	**8**	-
Commodity contracts[3]	**(114)**	(35)	**(298)**	(227)
Other contracts[4]	**5**	(1)	**11**	1
Total unrealized derivative fair value gain/(loss)	**(77)**	352	**765**	(1,131)

1 Reported within Transportation and other services revenues (2016 - $564 million gain; 2015 - $571 million loss) and Other income/(expense) (2016 - $480 million gain; 2015 - $334 million loss) in the Consolidated Statements of Earnings.

2 Reported as a decrease to Interest expense in the Consolidated Statements of Earnings.

3 Reported within Transportation and other services revenues (2016 - $2 million gain; 2015 - $5 million gain), Commodity sales (2016 - $302 million loss; 2015 - $357 million loss), Commodity costs (2016 - $6 million gain; 2015 - $118 million gain) and Operating and administrative expense (2016 - $4 million loss; 2015 - $7 million gain) in the Consolidated Statements of Earnings.

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

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintains substantial capacity under its committed bank lines of credit to address any contingencies. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company also maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. 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 June 30, 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, netting arrangements and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

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

	June 30, 2016	December 31, 2015
(millions of Canadian dollars)		
Canadian financial institutions	**40**	47
United States financial institutions	**281**	450
European financial institutions	**107**	95
Asian financial institutions	**10**	4
Other[1]	**356**	213
	794	809

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

As at June 30, 2016, the Company had provided letters of credit totalling $325 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held no cash collateral on derivative asset exposures as at June 30, 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:

June 30, 2016	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**97**	**-**	**97**
Interest rate contracts	**-**	**1**	**-**	**1**
Commodity contracts	**3**	**119**	**384**	**506**
Other contracts	**-**	**3**	**-**	**3**
	3	**220**	**384**	**607**
Long-term derivative assets				
Foreign exchange contracts	**-**	**90**	**-**	**90**
Commodity contracts	**-**	**88**	**28**	**116**
	-	**178**	**28**	**206**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(754)**	**-**	**(754)**
Interest rate contracts	**-**	**(946)**	**-**	**(946)**
Commodity contracts	**(3)**	**(78)**	**(396)**	**(477)**
Other contracts	**-**	**(1)**	**-**	**(1)**
	(3)	**(1,779)**	**(396)**	**(2,178)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(2,130)**	**-**	**(2,130)**
Interest rate contracts	**-**	**(1,173)**	**-**	**(1,173)**
Commodity contracts	**-**	**(14)**	**(192)**	**(206)**
Other contracts	**-**	**(5)**	**-**	**(5)**
	-	**(3,322)**	**(192)**	**(3,514)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,697)**	**-**	**(2,697)**
Interest rate contracts	**-**	**(2,118)**	**-**	**(2,118)**
Commodity contracts	**-**	**115**	**(176)**	**(61)**
Other contracts	**-**	**(3)**	**-**	**(3)**
	-	**(4,703)**	**(176)**	**(4,879)**

December 31, 2015 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
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:

June 30, 2016 *(fair value in millions of Canadian dollars)*	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
Commodity contracts - financial1						
Natural gas	21	Forward gas price	3.41	4.91	4.10	$/mmbtu3
NGL	10	Forward NGL price	0.31	1.34	0.94	$/gallon
Power	(156)	Forward power price	27.25	76.42	53.36	$/MWH
Commodity contracts - physical1						
Natural gas	(59)	Forward gas price	2.35	5.00	3.55	$/mmbtu3
Crude	(39)	Forward crude price	44.26	73.57	61.33	$/barrel
NGL	4	Forward NGL price	0.22	1.87	0.87	$/gallon
Commodity options2						
Crude	21	Option volatility	27%	39%	31%	
NGL	21	Option volatility	7%	91%	38%	
Power	1	Option volatility	24%	42%	25%	
	(176)					

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

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

3 One million British thermal units (mmbtu).

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

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

	Six months ended June 30,	
	2016	2015
(millions of Canadian dollars)		
Level 3 net derivative asset at beginning of period	**54**	149
Total loss		
Included in earnings[1]	**(96)**	(49)
Included in OCI	**(8)**	(22)
Settlements	**(126)**	(152)
Level 3 net derivative liability at end of period	**(176)**	(74)

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

The Company s policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at June 30, 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 $123 million as at June 30, 2016 (December 31, 2015 - $126 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $350 million as at June 30, 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 June 30, 2016, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2015 - $580 million).

As at June 30, 2016, the Company s long-term debt had a carrying value of $38,045 million (December 31, 2015 - $41,530 million) before debt issuance cost and a fair value of $39,962 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 six months ended June 30, 2016, the Company recognized an unrealized foreign exchange gain on the translation of United States dollar denominated debt of $277 million (2015 - unrealized loss of $279 million) and an unrealized gain on the change in fair value of its outstanding foreign exchange forward contracts of $73 million (2015 - unrealized loss of $97 million) in OCI. The Company recognized a realized gain of $1 million (2015 - realized gain of $7 million) in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized gain of $33 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 six months ended June 30, 2016 (2015 - nil).

13. INCOME TAXES

The effective income tax rates for the three and six months ended June 30, 2016 were 2.8% and 20.1%, respectively (2015 - 35.4% and a recovery of 35.6%, respectively). The period-over-period increase in the effective tax rate for the six months is primarily attributable to the effects of rate-regulated accounting and other permanent items relative to lower earnings in the first six months of 2015 as compared with 2016, offset by the $39 million tax expense arising from the intercompany transfer of a partnership interest in 2015. The effective income tax rate for the six months ended June 30, 2015 was further impacted by an out-of-period adjustment (*Note 3*).

The period-over-period decrease in the effective tax rate for the three months ended June 30, 2016 is primarily due to the effects of rate-regulated accounting and other permanent items relative to lower earnings in 2016.

14. 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Benefits earned during the period	**41**	44	**83**	88
Interest cost on projected benefit obligations	**23**	26	**49**	53
Expected return on plan assets	**(38)**	(37)	**(76)**	(73)
Amortization of prior service costs	**-**	1	**-**	1
Amortization of actuarial loss	**9**	12	**18**	24
Net benefit costs on an accrual basis[1,2]	**35**	46	**74**	93

1 Included in net benefit costs for the three and six months ended June 30, 2016 are costs related to OPEB of $3 million and $7 million, respectively. (2015 - $4 million and $7 million).

2 For the three and six months ended June 30, 2016, offsetting regulatory liabilities of $3 million and $5 million, respectively (2015 - nil regulatory liabilities) have been recorded to the extent pension and OPEB costs are expected to be refunded to or collected from customers in future rates.

15. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As part of the acquisition of the Tupper Plants (*Note 4*), Enbridge committed to fund up to $1.0 billion of capital to expand the Tupper Plants facilities or to acquire or construct processing facilities in an area of mutual interest.

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 35.5% 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 June 30, 2016, EEP s cumulative cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge). This includes a reduction of estimated remediation efforts offset by 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 June 30, 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.

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, other than fines and penalties, 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 June 30, 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 June 30, 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 includes 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. Three 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.

Line 6B Fines and Penalties

As at June 30, 2016, included in EEP s total estimated costs related to the Line 6B crude oil release were US$69 million in fines and penalties. Of this amount, US$61 million relates to civil penalties under the Clean Water Act of the United States, which EEP fully accrued for.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan Southern Division (the Court) that is EEP s signed settlement agreement with the United States Environmental Protection Agency and the United States Department of Justice regarding Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, EEP will pay US$62 million in civil penalties: US$61 million in respect of Line 6B and US$1 million in respect of Line 6A. The Consent Decree will take effect upon approval by the Court, following a comment period.

In addition to the monetary fines and penalties discussed above, the Consent Decree calls for replacement of Line 3, which EEP initiated in 2014 and is currently under regulatory review in the State of Minnesota. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to EEP s comprehensive in-line inspection-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively these measures build on continuous improvements implemented since 2010 to EEP s leak detection program, control center operations and emergency response program. EEP estimates the total cost of these measures to be approximately US$110 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact the overall financial performance of EEP or the Company.

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.