ENBRIDGE INC
Form 6-K
November 03, 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 November 3, 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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 nine months ended September, 2016.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date: November 3, 2016	By: /s/ Tyler W. Robinson Tyler W. Robinson Vice President & Corporate Secretary

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

September 30, 2016

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016

This Management s Discussion and Analysis (MD&A) dated November 3, 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 nine months ended September 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 nine months ended September 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 impacts 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 the Company s financial performance and financial position on a consolidated basis.

MERGER AGREEMENT WITH SPECTRA ENERGY

On September 6, 2016 Enbridge and Spectra Energy Corp (Spectra Energy) announced that they had entered into a definitive merger agreement under which Enbridge and Spectra Energy would combine in a stock-for-stock merger transaction (the Merger Transaction), which valued Spectra Energy common stock at approximately $37 billion (US$28 billion), based on the closing price of Enbridge s common shares on September 2, 2016.

The Merger Transaction was unanimously approved by the Boards of Directors of both companies and is expected to close in the first quarter of 2017, subject to shareholder and certain regulatory approvals, and other customary conditions. The combination will create the largest energy infrastructure company in North America and one of the largest globally based on a pro-forma enterprise value of approximately $165 billion (US$127 billion) as measured at the time of the announcement.

Under the terms of the Merger Transaction, Spectra Energy shareholders will receive 0.984 shares of the combined company for each share of Spectra Energy common stock they own. Upon completion of the Merger Transaction, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%. The combined company will be called Enbridge Inc.

On September 23, 2016, Enbridge filed with the United States Securities and Exchange Commission on Form F-4, a preliminary Registration Statement with respect to the Merger Transaction, which included an updated value of the Spectra Energy common stock at approximately $40 billion (US$30 billion), based on the closing price of Enbridge s common shares on September 19, 2016. The final purchase price for the Merger Transaction may vary based on the market price of Enbridge s common shares at the time the Merger Transaction is completed. There is no assurance when or if the Merger Transaction will be completed.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**(87)**	179	**2,168**	1,131
Gas Distribution	**20**	27	**342**	344
Gas Pipelines and Processing	**67**	77	**147**	(298)
Green Power and Transmission	**34**	25	**124**	127
Energy Services	**(25)**	169	**(38)**	233
Eliminations and Other	**(102)**	(367)	**71**	(743)
Earnings/(loss) before interest and income taxes	**(93)**	110	**2,814**	794
Interest expense	**(397)**	(718)	**(1,178)**	(1,253)
Income taxes recovery/(expense)	**253**	(129)	**(174)**	(76)
Loss attributable to noncontrolling interests and redeemable noncontrolling interests	**207**	200	**166**	334
Preference share dividends	**(73)**	(72)	**(217)**	(214)
Earnings/(loss) attributable to common shareholders	**(103)**	(609)	**1,411**	(415)
Earnings/(loss) per common share	**(0.11)**	(0.72)	**1.56**	(0.49)
Diluted earnings/(loss) per common share	**(0.11)**	(0.72)	**1.55**	(0.49)

EARNINGS/(LOSS) BEFORE INTEREST AND INCOME TAXES

For the three and nine months ended September 30, 2016, loss before interest and income taxes was $93 million and EBIT was $2,814 million, respectively, compared with EBIT of $110 million and $794 million for the three and nine months ended September 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 in the second quarter of 2016 by the impacts of the northeastern Alberta wildfires discussed in *Recent Developments Liquids Pipelines Impact of Wildfires in Northeastern Alberta*. 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 September 30, 2016, the Company s EBIT reflected a $14 million unrealized derivative fair value loss compared with an $896 million unrealized derivative fair value loss in the corresponding 2015 period. For the nine months ended September 30, 2016, the Company s EBIT reflected $820 million of unrealized derivative fair value gains compared with a $1,938 million 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 the nine-month period-over-period EBIT was impacted by certain impairment charges recorded in the second and third quarters of 2016 and in the second quarter of 2015. In the third quarter of 2016, an impairment charge of $1,000 million ($81 million after-tax attributable to Enbridge) was recognized in relation to Enbridge Energy Partners, L.P. s (EEP) Sandpiper Project (Sandpiper). In September 2016, EEP announced that it had applied for the withdrawal of the regulatory applications for Sandpiper that were pending with the Minnesota Public Utilities Commission (MNPUC). In connection with this announcement and other factors, EEP evaluated Sandpiper for impairment and concluded the project was impaired and recorded an asset impairment of US$763 million, including related project costs. Of the total amount, US$270 million was allocated to Marathon Petroleum Corporation (MPC), EEP s partner in Sandpiper, and US$493 million was attributable to EEP s unit holders. The Company s Consolidated Statements of Earnings for the three and nine months ended September 30, 2016 included a gross charge of $1,000 million, of which $871 million was attributable to noncontrolling interests in EEP and MPC and $81 million after-tax attributable to Enbridge s common shareholders.

In the second quarter of 2016, an impairment of $176 million ($103 million after-tax attributable to Enbridge) was recorded relating 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. The comparability of the nine-month 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 EEP s natural gas and NGL businesses. Also impacting the comparability of the three and nine-month period-over-period EBIT were charges of $18 million ($10 million after-tax attributable to Enbridge) and $39 million ($22 million after-tax attributable to Enbridge), respectively, for costs incurred to bring pipelines and facilities back into service following the northeastern Alberta wildfires discussed in *Recent Developments Liquids Pipelines Impact of Wildfires in Northeastern Alberta.*

EARNINGS/(LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

Loss attributable to common shareholders was $103 million for the three months ended September 30, 2016, or $0.11 per common share, compared with a loss of $609 million, or $0.72 per common share, for the three months ended September 30, 2015. Earnings attributable to common shareholders were $1,411 million for the nine months ended September 30, 2016, or $1.56 per common share, compared with a loss of $415 million, or $0.49 per common share, for the nine months ended September 30, 2015.

In addition to the factors discussed in *Earnings/(Loss) Before Interest and Income Taxes* above and in *Adjusted Earnings*, the period-over-period comparability of earnings/(loss) attributable to common shareholders was impacted by a number of unusual, non-recurring and non-operating factors that are summarized and described under *Non-GAAP Reconciliation EBIT to Adjusted Earnings.*

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , believe , likely and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected available cash flow from operations (ACFFO); expected future cash flows; 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; expectations about the Company s joint venture partners ability to complete and finance projects under construction; expected closing of acquisitions and dispositions; estimated cost and impact to the Company s overall financial performance of complying with the settlement consent decree related to Line 6B and Line 6A; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; the Merger Transaction and expectation regarding the purchase price, timing and closing thereof; expectations regarding the impact of the Merger Transaction; expectations regarding the impact of the dividend payout policy and dividend payout expectation; expectations on impact of hedging program; strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy; expected timing of decisions from the Federal Cabinet (the Cabinet) relating to the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program); and expected timing of any Supreme Court of Canada decision with respect to the Northern Gateway Project (Northern Gateway).

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; the timing and completion of the Merger Transaction, including receipt of regulatory and shareholder approvals and the satisfaction of other conditions precedent; the realization of anticipated benefits and synergies of the Merger Transaction and the timing thereof; the success of integration plans; cost of complying with the settlement consent decree related to Line 6B and Line 6A; impact of the dividend policy on the Company s future cash flows; credit ratings; capital project funding; expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and 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 the impact of the Merger Transaction on the Company, 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 the impact of the Merger Transaction, 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, political decisions, supply of and demand for commodities and the settlement consent decree related to Line 6B and Line 6A, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted EBIT, adjusted earnings/(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 gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Management uses adjusted EBIT and adjusted earnings/(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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Earnings/(loss) before interest and income taxes	**(93)**	110	**2,814**	794
Adjusting items[1]:				
Changes in unrealized derivative fair value (gains)/loss[2]	**14**	896	**(820)**	1,938
Sandpiper asset impairment[3]	**1,000**	-	**1,000**	-
Goodwill impairment loss	**-**	-	**-**	440
Assets and investment impairment loss	**10**	-	**197**	20
Unrealized intercompany foreign exchange (gains)/loss	**(2)**	(55)	**53**	(110)
Hydrostatic testing	**(2)**	49	**(14)**	49
Make-up rights adjustments	**16**	5	**131**	(8)
Northeastern Alberta wildfires pipelines and facilities restart costs	**18**	-	**39**	-
Leak remediation costs, net of leak insurance recoveries	**(13)**	(1)	**3**	(5)
Warmer/(colder) than normal weather	**-**	-	**8**	(37)
Employee severance and restructuring costs	**22**	-	**30**	-
(Gains)/loss on sale of non-core assets and investment, net	**4**	(60)	**4**	(88)
Project development and transaction costs	**27**	21	**30**	42
Other	**-**	(7)	**(11)**	3
Adjusted earnings before interest and income taxes	**1,001**	958	**3,464**	3,038
Interest expense	**(397)**	(718)	**(1,178)**	(1,253)
Income taxes recovery/(expense)	**253**	(129)	**(174)**	(76)
Loss attributable to noncontrolling interests and redeemable noncontrolling interests	**207**	200	**166**	334
Preference share dividends	**(73)**	(72)	**(217)**	(214)
Adjusting items in respect of:				
Interest expense[4]	**12**	401	**36**	352
Income taxes[5]	**(330)**	(13)	**(210)**	(280)
Noncontrolling interests and redeemable noncontrolling interests[6]	**(236)**	(228)	**(331)**	(529)
Adjusted earnings	**437**	399	**1,556**	1,372

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 *Inclusive of $8 million of related project costs.*

4 *Interest expense for each period included changes in unrealized derivative fair value gains and losses on interest rate contracts. For the three and nine months ended September 30, 2015, interest expense also included a loss of $338 million on de-designation of interest rate hedges from the transfer of assets between entities under common control of Enbridge in connection with the transfer of Enbridge s Canadian liquids business and certain Canadian renewable energy assets to the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and its subsidiaries and investees) (the Canadian Restructuring Plan).*

5 *Income Taxes were impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items for earnings before interest and income taxes. In the third quarter of 2016, income taxes also included a recovery of $247 million related to an adjustment for a curing loss as described in footnote 6 below. Adjustments for income taxes also included 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. In the third quarter of 2015, income taxes included an $88 million write-off of a regulatory asset in respect of taxes in connection with the Canadian Restructuring Plan and a valuation allowance of $176 million in respect of deferred income tax assets related to EEP.*

6 *Noncontrolling interests and redeemable noncontrolling interests were also impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items for earnings before interest and income taxes, as well as adjusting items for interest expense and income taxes. Under EEP s partnership agreement, capital deficits cannot be accumulated in the capital account of any limited*

partner and thus, such capital account deficits are brought to zero or cured . During the third quarter of 2016, the book value of limited partnership capital accounts in EEP became negative, resulting in a reallocation of such deficit to the Company s general partnership account in EEP. For the third quarter of 2016, earnings attributable to noncontrolling interests were higher by $652 million due to such reallocation. In the case of any additional losses or unanticipated charges to EEP in future periods, curing may occur in such periods.

NON-GAAP RECONCILIATION   ADJUSTED EBIT TO ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**941**	895	**2,947**	2,435
Gas Distribution	**31**	24	**344**	318
Gas Pipelines and Processing	**94**	84	**271**	248
Green Power and Transmission	**34**	26	**122**	126
Energy Services	**(15)**	(23)	**33**	83
Eliminations and Other	**(84)**	(48)	**(253)**	(172)
Adjusted earnings before interest and income taxes	**1,001**	958	**3,464**	3,038
Interest expense[1]	**(385)**	(317)	**(1,142)**	(901)
Income taxes[1]	**(77)**	(142)	**(384)**	(356)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(29)**	(28)	**(165)**	(195)
Preference share dividends	**(73)**	(72)	**(217)**	(214)
Adjusted earnings	**437**	399	**1,556**	1,372
Adjusted earnings per common share	**0.47**	0.47	**1.72**	1.62

1 These balances are presented net of adjusting items.

Adjusted EBIT

For the three and nine months ended September 30, 2016, adjusted EBIT was $1,001 million and $3,464 million, respectively, an increase of $43 million and $426 million over the corresponding periods in 2015.

Growth in consolidated adjusted EBIT was largely driven by stronger contributions from the Company s 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 increased access to the eastern Canada and Patoka markets, respectively.

The Canadian Mainline and Regional Oil Sands System contributions increased in the first nine months 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 have resulted in a negative impact of approximately $74 million on the Company s adjusted EBIT for the nine-month period in 2016. Growth in Canadian Mainline adjusted EBIT was also affected by a combination of a lower average International Joint Tariff (IJT) Residual Benchmark Toll, which decreased effective April 1, 2016, and a lower foreign exchange hedge rate used to record Canadian Mainline revenues, resulting in a quarter-over-quarter decrease in Canadian Mainline adjusted EBIT.

7

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

Within the Gas Distribution segment, EGD adjusted EBIT increased for each of the three and nine-month periods in 2016 compared with the corresponding 2015 periods. The increase in adjusted EBIT was primarily due to growth in EGD s rate base and customer growth.

For the three and nine-month periods ended September 30, 2016, 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) acquired on April 1, 2016. These positive effects were partially offset by the impact of lower volumes on US Midstream pipelines due to reduced drilling by producers. For the three months ended September 30, 2016, Aux Sable also delivered an increase in adjusted EBIT period-over-period, primarily due to an improvement in fractionation margins and lower feedstock supply costs.

The Green Power and Transmission segment delivered lower adjusted EBIT for the first nine months of 2016 mainly attributable to disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades. Adjusted EBIT for the third quarter of 2016 was higher compared with the third quarter of 2015 as a result of stronger wind resources at the Company s United States wind farms.

Adjusted EBIT from Energy Services for the nine months ended September 30, 2016 decreased relative to the prior year period due to compression of certain crude oil location and quality differentials and the impact of a weaker NGL market. These negative effects were partially offset by contributions from increased crude oil storage opportunities in the third quarter of 2016 which also resulted in a quarter-over-quarter decrease in adjusted loss before interest and income taxes.

Adjusted Earnings

Adjusted earnings were $437 million, or $0.47 per common share, for the three months ended September 30, 2016 compared with $399 million, or $0.47 per common share, for the three months ended September 30, 2015. Adjusted earnings were $1,556 million, or $1.72 per common share, for the nine months ended September 30, 2016 compared with $1,372 million, or $1.62 per common share, for the nine months ended September 30, 2015.

The period-over-period increase 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 for the nine-month period remained unchanged at $26 million and $0.03, respectively, since the end of the second quarter of 2016. 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 nine-month periods ended September 30, 2016 was higher compared with the corresponding 2015 periods resulting from debt incurred 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 for the nine months ended September 30, 2016 largely due to the period-over-period increase in earnings.

Adjusted earnings attributable to noncontrolling interests and redeemable noncontrolling interests decreased for the nine months ended September 30, 2016 compared with the corresponding period in 2015. Although EEP s performance 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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**1,001**	958	**3,464**	3,038
Depreciation and amortization[1]	**562**	524	**1,676**	1,483
Maintenance capital[2]	**(171)**	(204)	**(466)**	(520)
	1,392	1,278	**4,674**	4,001
Interest expense[3]	**(385)**	(317)	**(1,142)**	(901)
Current income taxes[3]	**20**	(31)	**(61)**	(107)
Preference share dividends	**(73)**	(72)	**(217)**	(214)
Distributions to noncontrolling interests	**(176)**	(177)	**(538)**	(501)
Distributions to redeemable noncontrolling interests	**(53)**	(27)	**(148)**	(80)
Cash distributions in excess of equity earnings[3]	**95**	54	**116**	180
Other non-cash adjustments	**32**	(40)	**150**	(100)
Available cash flow from operations (ACFFO)	**852**	668	**2,834**	2,278
1 Depreciation and amortization:				
Liquids Pipelines	***343***	*324*	***1,025***	*891*
Gas Distribution	***87***	*73*	***251***	*230*
Gas Pipelines and Processing	***73***	*69*	***222***	*202*
Green Power and Transmission	***47***	*47*	***142***	*139*
Energy Services	***-***	*(1)*	***1***	*(1)*
Eliminations and Other	***12***	*12*	***35***	*22*
	562	*524*	***1,676***	*1,483*
2 Maintenance capital:				
Liquids Pipelines	***(59)***	*(94)*	***(131)***	*(234)*
Gas Distribution	***(86)***	*(70)*	***(251)***	*(184)*
Gas Pipelines and Processing	***(8)***	*(13)*	***(31)***	*(28)*
Green Power and Transmission	***(2)***	*-*	***(3)***	*-*
Eliminations and Other	***(16)***	*(27)*	***(50)***	*(74)*
	(171)	*(204)*	***(466)***	*(520)*

3 These balances are presented net of adjusting items.

Available Cash Flow from Operations

ACFFO was $852 million for the three months ended September 30, 2016 compared with $668 million for the three months ended September 30, 2015. ACFFO was $2,834 million for the nine months ended September 30, 2016 compared with $2,278 million for the nine months ended September 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, as well as other items discussed below. For the nine months ended September 30, 2016, ACFFO was negatively impacted by $74 million due to the northeastern Alberta wildfires.

Maintenance capital expenditures decreased period-over-period as higher expenditures in the Company s Gas Distribution segment were more than offset by lower maintenance capital expenditures in the Liquids Pipelines segment. The lower spending in Liquids Pipelines reflected a shift in the timing of maintenance activities to 2017 on certain leasehold improvements, as well as scope refinements to certain projects resulting from ongoing communication with regulators.

ACFFO also includes cash distributions from the Company s equity investments. Excluding the impact of an impairment of an equity investment in the second quarter of 2016, the Company s equity earnings and distributions from such investments for the nine months ended September 30, 2016 were higher compared with the corresponding 2015 period and reflected improved performance of such investments, as well as distributions from assets placed into service in recent years.

Other non-cash adjustments include various non-cash items presented in the Company s Consolidated Statements of Cash Flows, as well as adjustments for unearned revenues received during the period.

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.

The increase in ACFFO was also partially offset by increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in the Fund Group. A higher per unit distribution and the effects of strengthening United States dollar versus the Canadian dollar resulted in greater distributions to noncontrolling interests in EEP during the first half of 2016. Higher distributions to redeemable noncontrolling interests in the Fund Group were a result of a higher per unit distribution and increased public ownership in the Fund Group.

NON-GAAP RECONCILIATION ACFFO

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

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Cash provided by operating activities - continuing operations	**922**	917	**4,153**	3,799
Adjusted for changes in operating assets and liabilities1	**299**	432	**90**	180
	1,221	1,349	**4,243**	3,979
Distributions to noncontrolling interests	**(176)**	(177)	**(538)**	(501)
Distributions to redeemable noncontrolling interests	**(53)**	(27)	**(148)**	(80)
Preference share dividends	**(73)**	(72)	**(217)**	(214)
Maintenance capital expenditures2	**(171)**	(204)	**(466)**	(520)
Significant adjusting items:				
Weather normalization	**-**	-	**6**	(27)
Project development and transaction costs	**27**	35	**30**	42
Realized inventory revaluation allowance3	**(63)**	(257)	**(346)**	(422)
Employee severance and restructuring costs	**22**	-	**30**	-
Other items	**118**	21	**240**	21
Available cash flow from operations (ACFFO)	**852**	668	**2,834**	2,278

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 September 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.

As part of the planned integration of Enbridge and Spectra Energy under the proposed Merger Transaction, the Company s existing United States sponsored vehicle strategy, which includes EEP and MEP, will be reviewed in context of the combined enterprise. Thus, while the Company continues to progress its strategic evaluation of its two existing United States sponsored vehicles, it is possible that the evaluation and potential execution of any such strategies could be affected by the merger and extend into 2017.

LIQUIDS PIPELINES

Disposition of South Prairie Region Assets

On September 29, 2016, EIPLP entered into an agreement to sell the South Prairie Region assets within Feeder Pipelines and Other to an unrelated party for cash proceeds of $1.075 billion, subject to adjustment. The transaction is expected to close at the end of the fourth quarter of 2016.

Bakken Pipeline System

On August 2, 2016, Enbridge and EEP announced that EEP had entered into an agreement with MPC to form a new joint venture, which in turn has entered into an agreement to acquire a 49% equity interest in the holding company that owns 75% of the Bakken Pipeline System (the System) from an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. Under this arrangement, EEP and MPC would indirectly hold 75% and 25% interests, respectively, of the joint venture s 49% interest in the holding company of the System. The purchase price of EEP s effective 27.6% interest in the System is US$1.5 billion. In September 2016, Enbridge and EEP announced a tentative joint funding arrangement whereby Enbridge is expected to fund 75% of the US$1.5 billion investment. The remaining 25% of the investment is expected to be funded by EEP s issuance of a new class of limited partner units to Enbridge. Closing of the transaction is subject to a number of customary conditions, not all of which have been met at this time.

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. The Company 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, with oil sands production substantially coming back online by the end of June 2016. 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 represented an approximate 10% decrease in throughput compared with the throughput that the Company was delivering prior to the wildfires. In the third quarter of 2016, throughput on the Company s mainline system and overall system utilization strengthened. As a result, the negative impact of reduced system deliveries on revenues impacting the Company s adjusted EBIT and ACFFO for the nine-month period remained unchanged since the end of the second quarter of 2016 at approximately $74 million. The Company s adjusted earnings and adjusted earnings per share for the nine months ended September 30, 2016 were reduced by $26 million and $0.03, respectively.

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 September 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 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 September 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.

Enbridge has renewed its comprehensive property and liability insurance programs with a liability program aggregate limit of US$900 million, which includes sudden and accidental pollution liability. The insurance programs are effective May 1, 2016 through April 30, 2017. 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.

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 September 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 September 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.

In addition, and separate from the ongoing Line 6B claim, for the three and nine months ended September 30, 2016, EEP recorded an insurance recovery of US$10 million ($1 million after-tax attributable to Enbridge) associated with Line 6A Romeoville crude oil release, which occurred in 2010. This is the total insurance recovery available for that incident.

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 September 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.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan Southern Division (the Court). The Consent Decree is EEP s signed settlement agreement with the United States Environmental Protection Agency (EPA) and the United States Department of Justice regarding 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.

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 centre 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. The FERC accepted the compliance filing by order dated August 17, 2016. Seaway Pipeline has filed new uncommitted rates in accordance with that order. Going forward, Seaway Pipeline s uncommitted rates may be adjusted annually based on the FERC index, unless and until the FERC approves Seaway Pipeline s application for market-based ratemaking authority.

GAS PIPELINES AND PROCESSING

Aux Sable Legal Matter

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

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 ongoing. 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. 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 has been no decision yet issued on the matter and the litigants have requested that the New Brunswick courts temporarily refrain from issuing a decision, to allow time to evaluate a possible settlement of the matter. The litigants have committed to a framework of settlement and are working through the necessary negotiations and details to make it effective**.**

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

GROWTH PROJECTS COMMERCIALLY SECURED PROJECTS

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

(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	$2.1 billion	2017	Under construction
4.	Norlite Pipeline System (the Fund Group)[4]	$1.3 billion	$0.6 billion	2017	Under construction
5.	Lakehead System Mainline Expansion (EEP)[3]	US$0.8 billion	US$0.7 billion	2016-2019 (in phases)	Under construction
6.	Canadian Line 3 Replacement Program (the Fund Group)[5]	$4.9 billion	$1.5 billion	2019	Pre-construction
7.	U.S. Line 3 Replacement Program (EEP)[5]	US$2.6 billion	US$0.4 billion	2019	Pre-construction
8.	Sandpiper Project (EEP)[6]	US$2.6 billion	US$0.8 billion	Application withdrawn	Application withdrawn
GAS DISTRIBUTION					
9.	Greater Toronto Area Project	$0.9 billion	$0.9 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	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.	Chapman Ranch Wind Project	US$0.4 billion	US$0.1 billion	2017	Under construction
19.	Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.3 billion (£0.15 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 September 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 *As discussed under* Line 3 Replacement Program *below, the expected cost and in-service date of this project is under review by the Company in light of the schedule for regulatory review and approval communicated by the MNPUC on October 28, 2016.*
6 *The Company planned to construct and operate Sandpiper with MPC funding 37.5% of the project. However, on October 28, 2016, the MNPUC approved EEP s application to withdraw the Sandpiper regulatory applications without conditions.*

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. EEP will have the option to increase its economic interest by up to an additional 15% at cost through the June 2017 anniversary of the in-service date. In July 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 offset 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 targeted 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. Included therein was additional tankage of approximately US$0.4 billion which was completed on various dates between the third quarter of 2015 and 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). The expenditures incurred to date are approximately US$0.7 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. In July 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 offset 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 $1.5 billion. With a delay in construction arising from a longer than anticipated permitting process, the cost of this project is expected to increase. Also, in view of the MNPUC s decision in respect of the schedule for the remainder of the regulatory approval process for the U.S. L3R Program, as discussed in *United States Line 3 Replacement Program (EEP)* below, the Company is reviewing the expected impact on the Canadian L3R Program s schedule and cost estimates. It is possible that the in-service date could be delayed, at least until later in 2019. 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 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 docket 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.

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 a final 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 a final 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 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 addressed the comments received on the draft EIS scope and issued its scoping recommendations to the MNPUC on September 22, 2016.

Three external parties filed motions requesting that the scoping process be re-opened or that a comment period be established because of the issuance of the Consent Decree settling the Line 6B pipeline crude oil release in Marshall, Michigan and the withdrawal of regulatory applications pending with the MNPUC with respect to the Sandpiper pipeline project discussed below. EEP filed a reply challenging the need to re-open the scoping process indicating that neither of these events warrants further extension of time. The motions filed by the external parties were considered and denied by the MNPUC at a hearing held on October 28, 2016.

At the hearing on October 28, 2016, the MNPUC also finalized the scope of the EIS and established a firm date by which it must be completed, thereby providing much greater clarity with respect to the process and timeline for the regulatory approval of the U.S. L3R Program in Minnesota. The MNPUC s decision will be confirmed in a written order expected to be issued by the MNPUC shortly. EEP currently is evaluating the impact of the decision on the cost and in-service date of this project. It is possible, under the schedule approved by the MNPUC, that the in-service date could be delayed, at least until later in 2019. The assessment of the impact of the decision is ongoing and EEP will review the written order when issued and seek to further clarify the impact on the overall project schedule at that time.

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)

On September 1, 2016, EEP announced that it applied for the withdrawal of regulatory applications for Sandpiper pending with the MNPUC because EEP concluded that the project should be delayed until such time as crude oil production in North Dakota recovers sufficiently to support development of new pipeline capacity. Based on updated projections, EEP expects that this pipeline capacity will not likely be needed until beyond its current five-year planning horizon. On October 28, 2016, the MNPUC approved EEP s application to withdraw the regulatory applications without conditions.

In connection with the above announcement and other factors, EEP also evaluated Sandpiper for impairment and determined that the project was impaired. In the third quarter of 2016, EEP recorded an asset impairment of US$763 million, including related project costs. Of the total amount, US$270 million was allocated to MPC, EEP s partner in Sandpiper, and US$493 million was attributable to EEP s unit holders. The Company s Consolidated Statements of Earnings for the three and nine months ended September 30, 2016 included a gross charge of $1,000 million, of which $871 million was attributable to noncontrolling interests in EEP and MPC and $81 million after-tax attributable to Enbridge s common shareholders.

As part of the Light Oil Market Access Program initiative, EEP planned to undertake Sandpiper, which would have expanded and extended EEP s North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System would have been expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion involved 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 would have twinned 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.

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 $0.9 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. 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 September 2016, the Company completed the expansion of fractionation capacity and related facilities at the Aux Sable extraction and fractionation plant located in Channahon, Illinois. The expansion provides approximately 24,500 bpd of incremental fractionation capacity and 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 Company s share of the project cost was approximately US$0.1 billion.

GREEN POWER AND TRANSMISSION

Chapman Ranch Wind Project

On September 9, 2016, Enbridge acquired a 100% interest in the 249-megawatts Chapman Ranch Wind Project (Chapman Ranch), located in Nueces County, Texas, from Apex Clean Energy Holdings, LLC. Enbridge s total investment is expected to be approximately US$0.4 billion, with expenditures incurred to date of approximately US$0.1 billion. Chapman Ranch will consist of 81 Acciona Windpower North America, LLC (Acciona) turbines and is expected to be in service in 2017. The project will be constructed under a fixed-price engineering, procurement and construction agreement, with Renewable Energy Systems America Inc. Acciona will provide turbine operations and maintenance services under a five-year fixed-price contract with an option to extend. The project is backed by a 12-year offtake agreement.

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 GIC has stated that it will make a redetermination decision by November 25, 2016.

The deadline for seeking Leave to Appeal to the Supreme Court of Canada was September 22, 2016. Neither Northern Gateway nor the Federal Government sought leave to appeal. Only one party from the Federal Court proceeding has sought leave to appeal of the Federal Court s dismissal of its challenge to the JRP Report. Northern Gateway expects that the Supreme Court of Canada will release its decision on this leave application in the first quarter of 2017.

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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Canadian Mainline	**206**	246	**692**	626
Lakehead System	**331**	278	**1,043**	811
Regional Oil Sands System	**105**	83	**286**	253
Mid-Continent and Gulf Coast	**163**	149	**504**	355
Southern Lights Pipeline	**44**	41	**124**	113
Bakken System	**48**	53	**156**	162
Feeder Pipelines and Other	**44**	45	**142**	115
Adjusted earnings before interest and income taxes	**941**	895	**2,947**	2,435
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(7)**	(697)	**549**	(1,271)
Canadian Mainline - Line 9B costs incurred during reversal	**-**	(1)	**-**	(3)
Lakehead System - changes in unrealized derivative fair value gains/(loss)	**1**	1	**(4)**	(7)
Lakehead System - hydrostatic testing	**2**	(49)	**14**	(49)
Lakehead System - leak remediation costs	**-**	-	**(21)**	-
Lakehead System - leak insurance recovery	**13**	-	**13**	-
Regional Oil Sands System - northeastern Alberta wildfires pipelines and facilities restart costs	**(18)**	-	**(39)**	-
Regional Oil Sands System - make-up rights adjustment	**3**	(2)	**(31)**	12
Regional Oil Sands System - leak insurance recoveries	**-**	-	**5**	12
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**-**	1	**-**	(7)
Regional Oil Sands System - loss on disposal of non-core assets	**-**	(9)	**-**	(9)
Regional Oil Sands System - prior period adjustment	**-**	21	**-**	21
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value loss	**-**	(1)	**(1)**	(5)
Mid-Continent and Gulf Coast - make-up rights adjustment	**(19)**	(2)	**(97)**	(7)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**(1)**	(46)	**25**	(79)
Bakken System - Sandpiper asset impairment	**(1,000)**	-	**(1,000)**	-
Bakken System - make-up rights adjustment	**1**	-	**1**	8
Bakken System - changes in unrealized derivative fair value gains/(loss)	**-**	1	**(3)**	(3)
Feeder Pipelines and Other - investment impairment loss	**(2)**	-	**(178)**	-
Feeder Pipelines and Other - derecognition of regulatory balances	**-**	-	**(6)**	-
Feeder Pipelines and Other - gain on sale of non-core assets	**-**	69	**-**	91
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	(1)	**(3)**	(6)
Feeder Pipelines and Other - project development costs	**-**	(1)	**(3)**	(2)
Earnings/(loss) before interest and income taxes	**(87)**	179	**2,168**	1,131

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, as well as charges in 2015, 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, as well as insurance recoveries associated with the Line 6A crude oil release. Refer to *Recent Developments Liquids Pipelines Lakehead System Line 6B Crude Oil Release*.

- Regional Oil Sands System EBIT for each period included 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.

- 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.

- 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.

- Bakken System loss before interest and income taxes for 2016 reflected impairment charges, including related project costs, on EEP s Sandpiper resulting from the withdrawal of the regulatory applications in September 2016 that were pending with the MNPUC. For additional information, refer to *Growth Projects Commercially Secured Projects Liquids Pipelines Sandpiper Project (EEP)*.

- 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 nine months ended September 30, 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 nine months 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 nine months ended September 30, 2016.

The positive effect of increased capacity on Canadian Mainline throughput discussed above was partially offset in the second quarter of 2016 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 deliveries to Enbridge s downstream pipelines, including the Canadian Mainline. During the third quarter of 2016, throughput on the Company s mainline system and overall system utilization strengthened. The impact of the wildfires for the nine months ended September 30, 2016 on Canadian Mainline adjusted EBIT has remained unchanged since the end of the second quarter of 2016 at approximately $30 million. For further details on the wildfires, refer to *Recent Developments Liquids Pipelines 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. Effective July 1, 2016, Canadian Mainline IJT Residual Benchmark Toll increased slightly to US$1.47.

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 nine months ended September 30, 2016, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.047 and $1.067, respectively, compared with $1.113 and $1.097 for the corresponding 2015 periods.

In addition to the factors noted above, which partially offset the increase in Canadian Mainline adjusted EBIT for the nine months ended September 30, 2016, higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities also partially offset the increase.

The decrease in Canadian Mainline IJT Residual Benchmark Toll and lower foreign exchange hedge rate also 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 $11 million and $33 million were recorded for the three and nine months ended September 30, 2016, respectively (2015 - $10 million and $27 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 nine months ended September 30, 2016 and 2015 is provided below:

September 30,	**2016**	2015
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.05**	$4.07
Lakehead System Local Toll[2]	**$2.58**	$2.44
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.47**	$1.63

1 *The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(thousands of bpd)				
Average throughput volume[1]	**2,353**	2,212	**2,379**	2,165

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

Lakehead System

Lakehead System adjusted EBIT increased for the three and nine months ended September 30, 2016 compared with the corresponding 2015 periods. The period-over-period increases 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 nine-month period ended September 30, 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$255 million and US$790 million for the three and nine months ended September 30, 2016, respectively, compared with US$213 million and US$646 million for the corresponding 2015 periods. The period-over-period increases reflected higher Lakehead System Local Toll and 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 three and nine months ended September 30, 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 negative impact of the wildfires for the nine-month period on Lakehead System adjusted EBIT has remained unchanged since the end of the second quarter of 2016 at approximately $38 million. Also partially offsetting the period-over-period increases in adjusted EBIT were higher operating and administrative costs and higher depreciation expense from an increased asset base. Adjusted EBIT for the nine months ended September 30, 2016 also reflected incremental power costs associated with higher throughput.

As noted above, positively impacting Lakehead System adjusted EBIT for the nine months ended September 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 in the first half of 2016. The Exchange Rate was $1.31 and $1.32 for the three and nine months ended September 30, 2016, respectively, compared with $1.31 and $1.26 in the corresponding 2015 periods. The Exchange Rate was comparable quarter-over-quarter, resulting in a minimal impact on Lakehead System adjusted EBIT for the three months ended September 30, 2016 compared with the corresponding 2015 period. A portion of Lakehead System United States dollar EBIT is hedged as part of the Company s enterprise-wide financial risk management program. The Company uses foreign exchange derivative instruments to manage the foreign exchange risk arising from its United States businesses, including the Lakehead System, and realized gains and losses from these derivative instruments are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Throughput Volume

	Three months ended September 30,	Nine months ended September 30,

	2016	2015	2016	2015
(thousands of bpd)				
Average throughput volume[1]	**2,495**	2,338	**2,558**	2,292

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 nine months ended September 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. For the nine-month period ended September 30, 2016, the increase in adjusted EBIT was partially offset by the effects of the wildfires in northeastern Alberta during the second quarter of 2016, as discussed under *Recent Developments Liquids Pipelines Impact of Wildfires in Northeastern Alberta*, which negatively impacted Regional Oil Sands System adjusted EBIT by approximately $6 million.

Mid-Continent and Gulf Coast

Mid-Continent and Gulf Coast adjusted EBIT increased for the three and nine months ended September 30, 2016, compared with the corresponding 2015 periods. The period-over-period increases 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 nine-month period ended September 30, 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$382 million for the three and nine months ended September 30, 2016, respectively, compared with US$116 million and US$281 million for the corresponding 2015 periods. The increase in adjusted EBIT for the three and nine-month periods primarily reflected higher transportation revenues resulting mainly from an increase in the level of committed take-or-pay volumes on Flanagan South. Adjusted EBIT for the nine months ended September 30, 2016 also reflected higher tariffs on Flanagan South in the first half of 2016. 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. Partially offsetting the period-over-period increase in adjusted EBIT was lower throughput on Spearhead Pipeline due to a temporary decline in shippers demand.

As noted above, positively impacting adjusted EBIT for the nine months ended September 30, 2016 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 OtherFor further details refer to *Eliminations and Other*.

Southern Lights Pipeline

Southern Lights Pipeline adjusted EBIT for the three and nine months ended September 30, 2016 increased compared with the corresponding 2015 periods, primarily reflecting a higher recovery of negotiated depreciation rates in 2016 transportation tolls.

Bakken System

Bakken System adjusted EBIT for the three and nine months ended September 30, 2016 decreased compared with the corresponding 2015 periods. The period-over-period decreases in adjusted EBIT reflected lower rates and lower rail revenues on the United States portion of the Bakken System. For the nine months ended September 30, 2016, the decrease in adjusted EBIT was partially offset by the translation of United States dollar earnings to Canadian dollars at a higher nine-month period-over-period Exchange Rate.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT from Bakken System s United States portion was US$32 million and US$105 million for the three and nine months ended September 30, 2016, respectively, compared with US$36 million and US$118 million for the corresponding 2015 periods. The decrease in period-over-period 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 due to expired contracts. 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 adjusted EBIT for the nine months ended September 30, 2016 was the favourable effect of translating United States dollar earnings at a higher Exchange Rate due to the strengthening United States dollar versus the Canadian dollar in the first half of 2016. Similar to Lakehead System, a portion of the United States dollar EBIT of the Bakken System in the United States is hedged as part of the Company s enterprise-wide financial risk management program, and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company s investment in United States businesses are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted EBIT increased for the nine months ended September 30, 2016 compared with the corresponding 2015 period, primarily reflecting new contributions from Southern Access Extension which was placed into service in the fourth quarter of 2015. These positive contributions were partially offset during the second and third quarters of 2016 by a decrease in adjusted EBIT from Eddystone Rail, primarily attributable to market conditions which impacted volumes at the rail facility. Adjusted EBIT for the nine months ended September 30, 2016 also reflected lower contributions from Toledo resulting from refinery turnarounds that negatively impacted Toledo volumes in the second and third quarters of 2016.

GAS DISTRIBUTION

Earnings before Interest and Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**30**	28	**277**	250
Noverco Inc. (Noverco)	**2**	(5)	**35**	31
Other Gas Distribution and Storage	**(1)**	1	**32**	37
Adjusted earnings before interest and income taxes	**31**	24	**344**	318
EGD - (warmer)/colder than normal weather	**-**	-	**(8)**	37
Noverco - changes in unrealized derivative fair value gains/(loss)	**(6)**	3	**(6)**	(11)
Noverco - asset impairment	**(5)**	-	**(5)**	-
Noverco - recognition of regulatory balances	**-**	-	**17**	-
Earnings before interest and income taxes	**20**	27	**342**	344

Additional details on items impacting Gas Distribution EBIT include:

- Noverco EBIT for 2016 included an asset impairment in relation to certain long-term assets not eligible for recovery through rates.

- 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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**30**	28	**277**	250
Interest expense	**(50)**	(40)	**(131)**	(115)
Income taxes recovery/(expense)	**14**	13	**(6)**	(17)
Adjusting items in respect of:				
Interest expense	**3**	4	**3**	4
Income taxes	**(1)**	(1)	**(3)**	9
Adjusted earnings/(loss)	**(4)**	4	**140**	131
EGD - (warmer)/colder than normal weather	**-**	-	**(6)**	27
EGD - changes in unrealized derivative fair value loss	**(2)**	(3)	**(2)**	(3)
Earnings/(loss) attributable to common shareholders	**(6)**	1	**132**	155

Compared with the corresponding 2015 periods, EGD adjusted earnings decreased for the three months and increased for the nine months ended September 30, 2016, respectively. The increase in adjusted earnings for the nine months ended September 30, 2016 primarily reflected higher distribution charges arising from growth in EGD s rate base, customer growth, as well as lower storage and transportation costs. These positive effects were partially offset by higher interest expense and higher depreciation expense due to higher asset base. The quarter-over-quarter decrease in EGD adjusted earnings was primarily attributable to higher interest and depreciation expenses, partially offset by higher distribution charges arising from growth in EGD s rate base, customer growth and higher transactional services revenues, primarily relating to storage optimization activities.

Noverco

Noverco adjusted EBIT increased for the three and nine months ended September 30, 2016 compared with the corresponding 2015 periods, primarily reflecting the timing of equity earnings adjustments between quarters.

Other Gas Distribution and Storage

Other Gas Distributions and Storage adjusted EBIT decreased for the three and nine months ended September 30, 2016 compared with the corresponding 2015 periods, primarily reflecting lower distribution revenues due to warmer weather in the New Brunswick region in 2016.

GAS PIPELINES AND PROCESSING

Earnings before Interest and Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Aux Sable	**1**	(7)	**(1)**	1
Alliance Pipeline	**48**	37	**144**	114
Vector Pipeline	**6**	5	**21**	20
Canadian Midstream	**28**	24	**77**	64
Enbridge Offshore Pipelines (Offshore)	**19**	4	**40**	10
US Midstream	**(4)**	24	**2**	49
Other	**(4)**	(3)	**(12)**	(10)
Adjusted earnings before interest and income taxes	**94**	84	**271**	248
Aux Sable - accrual for commercial arrangements	**-**	1	**-**	(15)
Alliance Pipeline - derecognition of regulatory balances	**-**	-	**-**	8
Alliance Pipeline - changes in unrealized derivative fair value gains/(loss)	**(1)**	(6)	**11**	(14)
Offshore - gain on sale of non-core assets	**-**	-	**-**	6
US Midstream - goodwill impairment loss	**-**	-	**-**	(440)
US Midstream - changes in unrealized derivative fair value gains/(loss)	**(19)**	12	**(116)**	(58)
US Midstream - assets impairment loss	**(3)**	-	**(14)**	(20)
US Midstream - loss on disposal of non-core assets	**(4)**	-	**(4)**	-
US Midstream - make-up rights adjustment	**-**	-	**(1)**	1
US Midstream - transfer of contracts	**-**	(14)	**-**	(14)
Earnings/(loss) before interest and income taxes	**67**	77	**147**	(298)

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 sold in the third quarter of 2016.

- 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 gains and losses on derivative financial instruments used to risk manage commodity price exposures.

Aux Sable

Aux Sable adjusted EBIT for the nine months ended September 30, 2016 decreased compared with the corresponding 2015 period, primarily reflecting lower fractionation margins in the first half of 2016 resulting from weakness in the commodity price environment. Fractionation margins improved in the third quarter of 2016 and together with lower feedstock supply costs compared with the third quarter of 2015, drove a quarter-over-quarter increase in adjusted EBIT.

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 nine months ended September 30, 2016, compared with the corresponding 2015 periods. The period-over-period increase in adjusted EBIT was 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. These positive effects were 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 nine months ended September 30, 2016, compared with the corresponding 2015 periods and reflected contributions from the Tupper Plants acquired on April 1, 2016.

Offshore

Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT was US$14 million and US$30 million for the three and nine months ended September 30, 2016, respectively, compared with US$3 million and US$8 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 in the first half of 2016, partially offset by a decrease in volumes in the Garden Banks Gas Pipeline in the third quarter of 2016. The favourable impact of translating United States dollar earnings at a higher Exchange Rate in the nine months ended September 30, 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 loss before interest and income taxes was US$3 million and adjusted EBIT was US$2 million for the three and nine months ended September 30, 2016, respectively, compared with adjusted EBIT of US$19 million and US$39 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 September 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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Green Power and Transmission	**34**	26	**122**	126
Adjusted earnings before interest and income taxes	**34**	26	**122**	126
Green Power and Transmission - changes in unrealized derivative fair value gains/(loss)	**-**	(1)	**2**	1
Earnings before interest and income taxes	**34**	25	**124**	127

Green Power and Transmission adjusted EBIT decreased for nine months ended September 30, 2016 compared with the corresponding 2015 period as a result of disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades, as well as weaker wind resources experienced at certain facilities in Canada during the first half of the year. These negative effects were partially offset by stronger wind resources at the Company s United States wind farms during the third quarter of 2016 which also drove a higher adjusted EBIT for the third quarter of 2016 compared with the corresponding 2015 period.

ENERGY SERVICES

Earnings before Interest and Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Energy Services	**(15)**	(23)	**33**	83
Adjusted earnings/(loss) before interest and income taxes	**(15)**	(23)	**33**	83
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(10)**	192	**(71)**	150
Earnings/(loss) before interest and income taxes	**(25)**	169	**(38)**	233

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 gains/(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 first nine months of 2016 compared with the corresponding 2015 period, reflecting weaker performance from Energy Services Canadian and United States operations mainly during the first half of 2016. The compression of certain crude oil location and quality differentials and the impact of a weaker NGL market drove a period-over-period decrease in adjusted EBIT. This decrease was partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first nine months of 2016, as well as positive contributions from increased crude oil storage opportunities in the third quarter of 2016. The positive crude oil storage opportunities were also a driver for the increase in adjusted EBIT in the third quarter of 2016 compared with the third quarter of 2015. 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.

From its United States operations, adjusted loss before interest and income taxes for the three months ended September 30, 2016 was US$9 million and adjusted EBIT for the nine months ended September 30, 2016 was US$18 million, respectively, compared with adjusted loss before interest and income taxes of US$12 million and adjusted EBIT of US$56 million for the corresponding 2015 periods.

ELIMINATIONS AND OTHER

Earnings before Interest and Income Taxes

(millions of Canadian dollars)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Operating and administrative	**(22)**	(20)	**(56)**	(48)
Realized foreign exchange derivative loss	**(69)**	(67)	**(220)**	(166)
Other	**7**	39	**23**	42
Adjusted loss before interest and income taxes	**(84)**	(48)	**(253)**	(172)
Changes in unrealized derivative fair value gains/(loss)	**29**	(354)	**434**	(641)
Unrealized intercompany foreign exchange gains/(loss)	**2**	55	**(53)**	110
Employee severance and restructuring costs	**(22)**	-	**(30)**	-
Project development and transaction costs	**(27)**	-	**(27)**	-
Drop down transaction costs	**-**	(20)	**-**	(40)
Earnings/(loss) before interest and income taxes	**(102)**	(367)	**71**	(743)

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 nine months ended September 30, 2016 was a realized loss of $69 million and $220 million, respectively, compared with $67 million and $166 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 nine months ended September 30, 2016 was US$261 million and US$783 million, respectively, compared with US$238 million and US$714 million for the three and nine months ended September 30, 2015. The average price to sell United States dollars for Canadian dollars for each of the three and nine months ended September 30, 2016 was $1.04, compared with $1.03 for each of the three and nine months ended September 30, 2015. The Exchange Rate for the three and nine months ended September 30, 2016 was $1.31 and $1.32, compared with $1.31 and $1.26 for the three and nine months ended September 30, 2015. As the hedged rate was lower than the Exchange Rate in each of the three and nine-month periods in 2016 and 2015, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for the three months ended September 30, 2016 was slightly greater than the comparative 2015 period due to a higher notional amount of foreign currency derivatives. The realized hedge loss for the nine months ended September 30, 2016 was greater than the comparative 2015 period due to higher notional amount of foreign currency derivatives and a greater unfavourable spread between the Exchange Rate and hedge 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 $1.31 and $1.32 for the three and nine months ended September 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.

Other adjusted EBIT decreased during the three and nine months ended September 30, 2016 when compared with the corresponding 2015 periods. The decrease reflected realized foreign exchange losses from the translation of certain intercompany balances and the absence of an intercompany gain recognized in 2015 on an intercompany loan which settled subsequent to September 30, 2015.

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. As discussed under *Recent Developments Liquids Pipelines Disposition of South Prairie Region Assets*, in September 2016, EIPLP entered into an agreement to sell its South Prairie Region liquids pipelines assets for proceeds of $1,075 million. The sale of these non-core assets at attractive valuations provides additional financing flexibility to the Company.

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.

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 September 30, 2016 and December 31, 2015.

		September 30, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge	2017 - 2020	**8,168**	**5,580**	**2,588**	6,988
Enbridge (U.S.) Inc.	2017 - 2018	**4,237**	**394**	**3,843**	4,470
EEP	2018 - 2020	**3,443**	**2,709**	**734**	3,598
EGD	2018 - 2019	**1,017**	**530**	**487**	1,010
The Fund	2019	**1,500**	**691**	**809**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**26**	**-**	**26**	28
EPI	2018	**3,000**	**908**	**2,092**	3,000
Enbridge Southern Lights LP	2018	**5**	**-**	**5**	5
MEP	2018	**1,062**	**590**	**472**	1,121
Total committed credit facilities		**22,458**	**11,402**	**11,056**	21,720

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

During the three and nine months ended September 30, 2016, the Company completed aggregate issuances of unsecured, medium-term notes of $1,100 million with maturities ranging from 10 to 30 years.

The Company also expanded its access to financial markets beyond North America to support its liquidity requirements on attractive terms. In the second quarter of 2016, 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 $330 million (December 31, 2015 - $349 million) of uncommitted demand credit facilities, of which $87 million (December 31, 2015 - $185 million) were unutilized as at September 30, 2016.

The Company s net available liquidity of $11,643 million as at September 30, 2016 was inclusive of $1,036 million of unrestricted cash and cash equivalents and net of bank indebtedness of $449 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 September 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 September 30, 2016, the Company s debt capitalization ratio was 63.8% compared with 65.5% as at December 31, 2015.

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

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

- Moody s Investor Services, Inc. affirmed the Company s issuer rating and medium-term notes and unsecured debt rating of Baa2, preference share rating of Ba1 and commercial paper rating of P-2 with negative outlook.

- Standard & Poor s Ratings Services (S&P) affirmed the Company s corporate credit rating and unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low) with stable outlook. S&P also affirmed the Company s global overall short-term rating of A-2. The Company s financial risk profile has been changed to significant from aggressive due to improved credit metrics on a pro forma basis.

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 $63 million related to EGD s receipt of cash from the Government of Ontario to fund its Green Investment Fund initiative program, 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 September 30, 2016 for which the major contributing factor 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 September 30, 2016, the Company s net available liquidity totalled $11,643 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.

SOURCES AND USES OF CASH

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Operating activities	**922**	917	**4,153**	3,799
Investing activities	**(1,268)**	(1,758)	**(5,200)**	(5,671)
Financing activities	**120**	605	**1,101**	1,516
Effect of translation of foreign denominated cash and cash equivalents	**5**	51	**(33)**	119
Increase/(decrease) in cash and cash equivalents	**(221)**	(185)	**21**	(237)

Significant sources and uses of cash for the three and nine months ended September 30, 2016 are summarized below:

Operating Activities

- The cash growth delivered by operations in the first nine months of 2016 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 included within operating activities were $301 million (2015 - $417 million) for the three months ended September 30, 2016 and $106 million (2015 - $145 million) for the nine months ended September 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

- The Company continues with the execution of its growth capital program which is further described in *Growth Projects Commercially Secured Projects.* The timing of project approval, construction and in-service dates impacts the timing of cash requirements. For the three and nine months ended September 30, 2016, additions to property, plant and equipment resulted in cash spending of $1,004 million and $3,963 million, respectively, compared with $1,747 million and $5,310 million spent in the corresponding 2015 periods. 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 nine months of 2015.

- The period-over-period decrease in cash used in investing activities was partially offset by higher spending on acquisitions in 2016 compared with 2015. The Company paid cash consideration of $539 million in the first half of 2016 for the acquisition of the Tupper Plants and $65 million in the third quarter of 2016 for the acquisition of Chapman Ranch, whereas it spent $106 million in the first half of 2015 on the acquisition of a midstream business by EEP.

- Also, 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 ongoing development costs of that Company.

Financing Activities

- The Company s financing requirements for the nine-month period ended September 30, 2016 were lower compared with the corresponding 2015 period due to the timing of various growth projects.

- During the first nine months in 2016, the Company s overall debt increased by only $14 million compared with an overall debt increase of $2,361 million for the comparable 2015 period. The decrease was mainly due lower debt requirements resulting from the timing of completion of various growth projects and other sources of funds, primarily the proceeds from the Company s common share issuance in March 2016, which were partly utilized to reduce the Company s credit facilities and commercial paper draws.

- The increase in common share dividends paid in 2016 was attributable to the increase in the common share dividend rate effective March 2016 and higher number of common shares outstanding primarily as a result of the common share issuance noted above.

- Distributions to redeemable noncontrolling interests in the Fund Group also increased during the first nine months of 2016 compared with the corresponding 2015 period mainly due to a higher per share distribution rate and a larger number of public shares outstanding in ENF.

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 September 30, 2016, dividends declared were $496 million (2015 - $400 million), of which $300 million (2015 - $230 million) were paid in cash and reflected in financing activities. The remaining $196 million (2015 - $170 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 nine months ended September 30, 2016, dividends declared were $1,448 million (2015 - $1,195 million), of which $857 million (2015 - $709 million) were paid in cash and reflected in financing activities. The remaining $591 million (2015 - $486 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 nine months ended September 30, 2016, 39.5% (2015 - 42.5%) and 40.8% (2015 - 40.7%) of total dividends declared were reinvested.

On November 1, 2016, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2016, to shareholders of record on November 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 $1,713 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 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 September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				