ENBRIDGE INC
Form 6-K
November 05, 2015

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 5, 2015

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Canada	**None**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area 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**

Indicate by check mark whether the Registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No **P**

If Yes is marked, indicate below the file number assigned to the Registrant in connection with Rule 12g3-2(b):

N/A

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. 333-185591 AND 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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 30, 2015.

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 5, 2015

By: /s/ Tyler W. Robinson
Tyler W. Robinson
Vice President & Corporate Secretary

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ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

September 30, 2015

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2015

This Management s Discussion and Analysis (MD&A) dated November 4, 2015 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, 2015, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company s Annual Report for the year ended December 31, 2014. 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.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines[1]	**(247)**	(31)	**(260)**	444
Gas Distribution	**(2)**	(11)	**176**	144
Gas Pipelines, Processing and Energy Services[1]	**104**	88	**174**	386
Sponsored Investments[1]	**87**	108	**182**	279
Corporate	**(551)**	(234)	**(687)**	(233)
Earnings/(loss) attributable to common shareholders from continuing operations	**(609)**	(80)	**(415)**	1,020
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**-**	46
Earnings/(loss) attributable to common shareholders	**(609)**	(80)	**(415)**	1,066
Earnings/(loss) per common share	**(0.72)**	(0.10)	**(0.49)**	1.29
Diluted earnings/(loss) per common share	**(0.72)**	(0.10)	**(0.49)**	1.27

1 *Effective September 1, 2015, Enbridge transferred its Canadian Liquids Pipelines business and certain Canadian renewable energy assets to the Fund Group (described below under* Adjusted Earnings*) within the Sponsored Investments segment as described under the Canadian Restructuring Plan, see* Recent Developments Sponsored Investments The Fund Group Canadian Restructuring Plan. *Losses from the Canadian Liquids Pipelines assets prior to the date of transfer of $350 million and $403 million in the three and nine month periods ended September 30, 2015, respectively, (2014 - loss of $59 million and earnings of $349 million, respectively) and earnings from the Canadian renewable energy assets within the Gas Pipelines, Processing and Energy Services segment prior to the date of transfer of $1 million and $1 million in the three and nine month periods ended September 30, 2015, respectively, (2014 - loss of $3 million and $8 million, respectively) have not been reclassified into the Sponsored Investments segment for presentation purposes.*

Loss attributable to common shareholders was $609 million for the three months ended September 30, 2015, or a loss of $0.72 per common share, compared with a loss of $80 million, or a loss of $0.10 per common share, for the three months ended September 30, 2014. The Company delivered strong quarter-over-quarter earnings growth as discussed in *Adjusted Earnings*; however, the visibility and the comparability of the Company s operating results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports the reliable cash flows and dividend growth upon which the Company s investor value proposition is based. The comparability of the Company s quarter-over-quarter loss was also impacted by the transfer of assets between entities under common control of Enbridge in connection with the Canadian Restructuring Plan which generated a number of one-time charges in the quarter including a $247 million loss on the de-designation of interest rate hedges, an $88 million write-off of a regulatory asset in respect of taxes and $16 million of transaction costs in the third quarter of 2015.

Partially offsetting these charges was a $44 million after-tax gain recognized in the third quarter of 2015 on the disposal of non-core assets within the Liquids Pipelines segment.

Loss attributable to common shareholders was $415 million for the nine months ended September 30, 2015, or a loss of $0.49 per common share, compared with earnings of $1,066 million, or $1.29 per common share, for the nine months ended September 30, 2014. In addition to the trends experienced in the three-month period discussed above, the comparability of the nine-month period-over-period was also impacted by a goodwill impairment charge of $440 million ($167 million after-tax attributable to Enbridge) recognized in the second quarter of 2015 related to Enbridge Energy Partners, L.P. s (EEP) natural gas and natural gas liquids (NGL) businesses. Due to a prolonged decline in commodity prices, a reduction in producers expected drilling programs has negatively impacted expected volumes on EEP s natural gas and NGL pipelines and processing systems, which EEP holds directly and indirectly through its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP). Earnings were also negatively impacted by a tax effect of the transfer of assets between entities under common control of Enbridge in the second quarter of 2015. The intercompany gain realized as a result of the transfer has been eliminated for accounting purposes. However, as the transaction involved the sale of partnership units, all tax consequences have remained in consolidated earnings and resulted in a charge of $39 million. The loss for the nine months ended September 30, 2015 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 tax expense in 2013 and 2014.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , believe , likely and similar words suggesting future outcomes or statements regarding outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected available cash flow from operations (ACFFO); expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; expected costs related to leak remediation and potential insurance recoveries; expectations regarding the impact of the Canadian Restructuring Plan (or the Transaction); dividend payout policy and dividend payout expectation.

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; expected exchange rates; inflation; interest rates; availability and price of labour and pipeline 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 impact of the Transaction and dividend policy on the Company s future cash flows; credit ratings; capital project funding; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and expected future ACFFO; and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) and adjusted earnings/(loss) and associated per share amounts, ACFFO, the impact of the Transaction on Enbridge or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated *completion dates and expected capital expenditures, include the following: the availability and price of labour and pipeline 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 Transaction, revised dividend policy, operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company s other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge s future course of action depends on management s assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company s behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss) and available cash flow from operations (ACFFO). Adjusted earnings/(loss) represents earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Adjusting items referred to as 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.

ACFFO is defined as cash flow provided by operating activities before changes in operating assets and liabilities (including changes in regulatory assets and liabilities and 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 earnings/(loss) and ACFFO provide useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Management uses adjusted 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 earnings/(loss), adjusted earnings/(loss) for each segment 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 in this section summarize the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Earnings/(loss) attributable to common shareholders	**(609)**	(80)	**(415)**	1,066
Adjusting items[1]:				
Changes in unrealized derivative fair value (gains)/loss[2]	**654**	396	**1,335**	156
Canadian Restructuring Plan	**351**	-	**351**	-
Goodwill impairment loss	**-**	-	**167**	-
Make-up rights adjustments	**8**	6	**-**	6
Leak remediation costs, net of leak insurance recoveries	**(1)**	16	**(4)**	17
Warmer/(colder) than normal weather	**-**	2	**(27)**	(35)
Gains on sale of non-core assets and investment, net of losses	**(37)**	-	**(46)**	(57)
Valuation allowance on deferred income tax assets	**32**	-	**32**	-
Project development and transaction costs	**2**	3	**14**	6
Tax on intercompany gains on sale of partnership units	**-**	-	**39**	-
Out-of-period adjustment	**-**	-	**(71)**	-
Other	**(1)**	2	**(3)**	6
Adjusted earnings	**399**	345	**1,372**	1,165

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.

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines[1]	**195**	221	**627**	659
Gas Distribution	**1**	(9)	**152**	109
Gas Pipelines, Processing and Energy Services[1]	**(21)**	20	**94**	106
Sponsored Investments[1]	**224**	126	**490**	306
Corporate	-	(13)	**9**	(15)
Adjusted earnings	**399**	345	**1,372**	1,165
Adjusted earnings per common share	**0.47**	0.41	**1.62**	1.41

1 Effective September 1, 2015, Enbridge completed the Transaction described under the Canadian Restructuring Plan, see Recent Developments Sponsored Investments The Fund Group Canadian Restructuring Plan. *Adjusted earnings from the Canadian Liquids Pipelines assets prior to the date of transfer of $128 million and $508 million in the three and nine month periods ended September 30, 2015, respectively, (2014 - $175 million and $542 million, respectively) and adjusted earnings from the Canadian renewable energy assets within the Gas Pipelines, Processing and Energy Services segment prior to the date of transfer of $2 million and $6 million in the three and nine month periods ended September 30, 2015, respectively, (2014 - loss of $2 million and $4 million, respectively) have not been reclassified into the Sponsored Investments segment for presentation purposes.*

Adjusted earnings were $399 million, or $0.47 per common share, for the three months ended September 30, 2015 compared with $345 million, or $0.41 per common share, for the three months ended September 30, 2014. Adjusted earnings were $1,372 million, or $1.62 per common share, for the nine months ended September 30, 2015 compared with $1,165 million, or $1.41 per common share, for the nine months ended September 30, 2014.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, adjusted earnings for the three and nine months ended September 30, 2015 are impacted by the effect of the Canadian Restructuring Plan. Following the close of the Canadian Restructuring Plan on September 1, 2015, adjusted earnings from Canadian Mainline and Regional Oil Sands System business are no longer reported in the Liquids Pipelines segment, but are captured in the results of the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust (ECT), Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) which are reported within the Sponsored Investments segment. Prior to the closing of the Canadian Restructuring Plan on September 1, 2015, period-over-period adjusted earnings from the Canadian Mainline increased reflecting positive effects of higher throughput, partly attributed to the expansion of the Company s mainline system completed in July 2015, higher terminalling revenues and a favourable United States/Canada foreign exchange rate. Partially offsetting these positive factors was a lower average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll, although this impact lessened commencing the second quarter of 2015 as effective April 1, 2015, this toll increased by US$0.10 per barrel to US$1.63 per barrel. Other factors negatively impacting adjusting earnings were higher power costs associated with higher throughput, higher depreciation expense due to an increased asset base and higher interest expense to support increased business activities. Partially mitigating the impact of a lower Canadian Mainline IJT Residual Benchmark Toll were new surcharges related to system expansions, including a surcharge for the Edmonton to Hardisty Expansion pipeline completed in April 2015. These trends continued into the month of September 2015, with Canadian Mainline adjusted earnings for the month of September 2015 now being reflected in the Fund Group, whereas, the adjusted earnings for the September 2014 period were reflected in Liquids Pipelines.
- Within Liquids Pipelines, adjusted earnings from the Seaway and Flanagan South Pipeline increased reflecting the partial alleviation of upstream apportionment through the expansion of the Company s mainline system completed in July 2015.
- Also within Liquids Pipelines, adjusted earnings continued to reflect lower earnings from Southern Lights Pipeline. The majority of the economic benefit derived from Southern Lights Pipeline is now reflected in earnings of the Fund Group following the Fund Group s November 2014 subscription and purchase of Class A units of certain Enbridge subsidiaries, which provide the Fund Group with a defined cash flow stream from Southern Lights Pipeline. Under the Canadian Restructuring Plan, the Fund Group also acquired full ownership interest in the Canadian segment of the Southern Lights Pipeline.
- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings increased reflecting customer growth, as well as higher distribution charges due to increased assets base. Also positively impacting adjusted earnings within Gas Distribution was the absence of a loss that Enbridge Gas New Brunswick Inc. (EGNB) incurred in 2014 under a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received.
- Within Gas Pipelines, Processing and Energy Services, adjusted loss in the third quarter of 2015 included a loss from Energy Services. After a very strong first half, the performance of Energy Services weakened in the third quarter as a result of less favourable conditions in certain markets accessed by committed transportation capacity, combined with an erosion of the favourable tank management opportunities experienced in the first half of 2015 due to a reduction in refinery demand for blended crude oil feedstock in the Gulf Coast.
- Also within Gas Pipelines, Processing and Energy Services, adjusted earnings/(loss) continued to reflect the absence of earnings from Alliance Pipeline US, which was transferred to the Fund Group in November 2014, as well as lower earnings from Aux Sable due to lower fractionation margins.
- Within Sponsored Investments, the increase in adjusted earnings from the Fund Group reflected one month of earnings from the Canadian liquids pipelines business and Canadian renewable energy assets as discussed above as well as Enbridge s overall 91.9% economic interest in the Fund Group, see *Recent Developments Sponsored Investments The Fund Group Canadian Restructuring Plan.* Higher adjusted earnings also continued to reflect the impact of the transfer of natural gas and diluent pipeline interests from Enbridge in 2014, partially offset by higher financing costs associated with the debt issued to partially finance that transfer and higher income taxes.

- Also within Sponsored Investments, adjusted earnings from EEP reflected higher throughput and tolls on EEP s major liquids pipelines, as well as contributions from new assets placed into service in 2014 and 2015, the most prominent being the replacement and expansion of Line 6B in 2014 and the expansion of the Company s mainline system completed in July 2015. EEP adjusted earnings also reflected incremental earnings from the January 2, 2015 transfer of the remaining 66.7% interest in Alberta Clipper previously held by Enbridge. Higher contribution from EEP for the nine months ended September 30, 2015 also reflected distributions from Class D units and Incentive Distribution Units (IDU) which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued by EEP in January 2015 in connection with the transfer of Alberta Clipper. However, overall contributions from EEP for the three months ended September 30, 2015 were comparable with the corresponding period in 2014 as the period-over-period adjusted earnings were impacted by the absence of incremental distributions from Class D units and IDU.
- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings for the nine months ended September 30, 2015 increased compared with the corresponding 2014 period, reflecting stronger operating earnings due to a favourable United States/Canada foreign exchange rate and incremental earnings from new assets, partially offset by lower preferred share dividend income based on a lower yield of 10-year Government of Canada bonds, to which the dividend rate is linked.
- Also within the Corporate segment, Other Corporate adjusted loss for the nine months ended September 30, 2015 decreased compared with the corresponding period in 2014 reflecting lower net Corporate segment finance costs, lower income taxes and the positive effects of foreign exchange rates on certain foreign currency balances, partially offset by higher preference share dividends reflecting additional preference shares issued in 2014 to fund the Company s growth capital program.

AVAILABLE CASH FLOW FROM OPERATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Cash provided by operating activities - continuing operations	**905**	746	**3,765**	1,872
Adjusted for changes in operating assets and liabilities1	**444**	310	**214**	1,307
	1,349	1,056	**3,979**	3,179
Distributions to noncontrolling interests	**(177)**	(135)	**(501)**	(395)
Distributions to redeemable noncontrolling interests	**(27)**	(18)	**(80)**	(55)
Preference share dividends	**(72)**	(63)	**(214)**	(174)
Maintenance capital expenditures2	**(204)**	(259)	**(520)**	(658)
Significant adjusting items3	**(201)**	28	**(386)**	(1)
Available cash flow from operations (ACFFO)	**668**	609	**2,278**	1,896

1 *Changes in operating assets and liabilities include changes in regulatory assets and liabilities and 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 *Included in significant adjusting items for the three months ended September 30, 2015 were weather normalization of nil (2014 - $2 million), project development and transaction costs of $35 million (2014 - $1 million), hydrostatic testing of $49 million (2014 - nil) and other items of ($28) million (2014 - $25 million). Included in significant adjusting items for the nine months ended September 30, 2015 were weather normalization of ($27) million (2014 - ($35) million), project development and transaction costs of $42 million (2014 - $4 million), hydrostatic testing of $49 million (2014 - nil), and other items of ($28) million (2014 - $30 million). Also included in significant adjusting items for the three and nine months ended September 30, 2015 were ($257) million (2014 - nil) and ($422) million (2014 - nil) in respect of losses on sale of previously written down inventory for which there is an approximate offsetting realized derivative gain in ACFFO.*

ACFFO was $668 million for the three months ended September 30, 2015 compared with $609 million for the three months ended September 30, 2014. ACFFO was $2,278 million for the nine months ended September 30, 2015 compared with $1,896 million for the nine months ended September 30, 2014.

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The Company experienced strong quarter-over-quarter and nine-month growth in ACFFO which was driven by the same factors as those impacting adjusted earnings across the Company s various businesses, as discussed in *Non-GAAP Measures Adjusted Earnings*. In addition, the significant growth capital program undertaken by the Company over recent years is also positioning the Company for future growth and new opportunities, and contributing to the ACFFO growth.

Also contributing to the period-over-period increase in ACFFO were lower maintenance capital expenditures in 2015 compared with the corresponding 2014 periods. Over the last few years, under its maintenance capital program, the Company has made a significant investment on the ongoing support and maintenance of the existing pipeline system and on maintaining the service capability of the existing assets. The period-over-period decrease in maintenance capital expenditures is due to the completion of certain maintenance programs in 2014. The Company plans to continue to invest in its maintenance capital program to support the safety and reliability of its operations.

The period-over-period increase in ACFFO was partially offset by distributions to noncontrolling interests in EEP and Enbridge Energy Management, L.L.C. and to redeemable noncontrolling interest in the Fund. Distributions were higher for each of the three and nine-month periods in 2015 compared with the corresponding 2014 periods. Also, the Company s payment of preference share dividends increased period-over-period due to preference shares issued in 2014 to fund the Company s growth capital program. Finally, the ACFFO was also adjusted for the cash effect of certain unusual, non-recurring or non-operating factors as discussed in *Non-GAAP Measures Non-GAAP Reconciliations*.

RECENT DEVELOPMENTS

LIQUIDS PIPELINES

United States Restructuring

A review of a potential transfer of Enbridge s United States liquids pipelines assets to EEP determined that conditions in the master limited partnership market do not support a large scale drop down at this time. The longer-term outlook for EEP remains strong, with over US$6 billion of secured growth projects coming into service through 2019 and options to increase its economic interest in projects that are jointly funded by Enbridge and EEP. EEP remains important to Enbridge s overall strategy and Enbridge continues to support EEP during this time of significant organic growth. Enbridge has a large inventory of United States liquids pipelines assets which are well suited to EEP and continues to evaluate opportunities to generate value through selective drop downs of ownership interests or assets of approximately $500 million annually to EEP depending on market conditions.

Seaway Pipeline Regulatory Matter

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. In relation to the original market-based rate application, the United States Federal Energy Regulatory Commission (FERC) issued its decision rejecting Seaway Pipeline s application for market-based rates in February 2014 and announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market-based rate application consistent with the new policy. In December 2014, Seaway Pipeline filed a new market-based rate application. The FERC noticed the application in the Federal Register and in response several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On September 17, 2015, the FERC issued its decision setting the application for hearing. The case has been assigned to an Administrative Law Judge (ALJ), who held a scheduling conference on October 1, 2015. The scheduling order calls for evidence to be filed on December 3, 2015, a hearing to start on July 7, 2016 and an initial decision of the ALJ on December 1, 2016.

Since the FERC had not issued a ruling on the market-based rate application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on Seaway Pipeline was challenged by several shippers. In September 2013, a decision from an ALJ was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ s findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on

October 15, 2013, challenging the ALJ s decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise her decision accordingly. On May 9, 2014, the ALJ issued an initial decision on remand reiterating her previous findings and did not change her decision. Briefings have concluded and the full record was sent to the FERC for its final decision, which is still pending.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) from the United States Environmental Protection Agency (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 believes to be an exceedance of currently permitted limits for Volatile Organic Material. Aux Sable received a second NFOV from the EPA in April 2015 in connection with this potential exceedance. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact.

SPONSORED INVESTMENTS THE FUND GROUP

Canadian Restructuring Plan

On September 1, 2015, Enbridge announced it had closed the transfer of its Canadian Liquids Pipelines business, held through Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines Athabasca Inc. (EPAI), and certain Canadian renewable energy assets to EIPLP, in which the Fund has an indirect interest, for aggregate consideration of $30.4 billion plus incentive distribution and performance rights (the Canadian Restructuring Plan or the Transaction).

The Transaction is a key component of Enbridge s Financial Optimization Strategy introduced in December 2014, which included an increase in the Company s targeted dividend payout. It advances the Company s sponsored vehicle strategy and supports Enbridge s previously announced 33% dividend increase effective March 1, 2015. The Transaction is expected to provide Enbridge with an alternate source of funding for its enterprise wide growth initiatives and enhance its competitiveness for new organic growth opportunities and asset acquisitions.

In conjunction with the execution of the Transaction, Enbridge adopted a supplemental cash flow metric, ACFFO, which was introduced in the second quarter of 2015 and is now a part of the Company s normal course quarterly reporting of financial performance and guidance provision. ACFFO is used to assess the performance of the Company s base business and expected growth program. The Company also started expressing its dividend payout range as a percentage of ACFFO rather than adjusted earnings. The target dividend payout policy range is 40% to 50% of ACFFO, which translates to approximately the previous payout range of 75% to 85% of adjusted earnings.

Consideration

Upon closing of the Transaction, Enbridge received $18.7 billion of units in the Fund Group, comprised of approximately $3 billion of units of the Fund and $15.7 billion of equity units of EIPLP, which at the time of the Transaction was an indirect subsidiary of the Fund. The Fund Group also assumed debt of EPI and EPAI of approximately $11.7 billion. In addition, a portion of the consideration to be received by Enbridge over time will be in the form of units which carry Temporary Performance Distribution

Rights (TPDR). The TPDR are designed to allow Enbridge to capture increasing value from the secured growth embedded within the transferred businesses; however, the cash flows derived from this incentive mechanism will be deferred (until such time as the units become convertible to a class of cash paying units in the fourth year after issuance).

Enbridge will continue to earn a base incentive fee from the Fund Group through management and incentive fees and Incentive Distribution Rights, which entitle it to receive 25% of the pre-incentive distributable cash flow above a base distribution threshold of $1.295 per unit, adjusted for a tax factor and paid out of ECT. Distributions over $1.890 per unit will be paid out of EIPLP. In addition, Enbridge received the TPDR, a distribution equivalent to 33% of pre-incentive distributable cash flow above the base distribution of $1.295 per unit. The TPDR will be paid in the form of Class D units of EIPLP and will be issued each month until the later of the end of 2020 or 12 months after the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) enters service. The Class D unitholders will receive a distribution each month equal to the per unit amount paid on Class C units of EIPLP, but to be paid in kind in additional Class D units. Each Class D unit is convertible into a cash paying Class C unit of EIPLP in the fourth year after its issuance.

The Fund units, Class A units of EIPLP and the EIPLP Class C units will pay a per unit cash distribution equivalent to the per unit cash distribution that the Fund pays on its units held by Enbridge Income Fund Holdings Inc. (ENF). The Fund units, EIPLP s Class C units and existing units of ECT also include an exchange right whereby they may be converted into common shares of ENF on a one-for-one basis.

Financing Plan

To acquire an increasing ownership interest in the Fund Group, the financing plan contemplates the issuance by ENF of $600 million to $800 million of public equity per year in one or more tranches through 2018 to fund an increasing investment in the Canadian Liquids Pipelines business. Enbridge has agreed to backstop the equity funding required by ENF to undertake the growth program embedded in the assets it acquired in the Transaction. The amount of public equity issued by ENF will be adjusted as necessary to match its capacity to raise equity funding on favourable terms. On October 13, 2015 ENF announced that it had entered into an agreement to issue approximately 21.5 million common shares for gross proceeds of approximately $700 million on a bought deal basis to a syndicate of underwriters. The offering is expected to close on or about November 6, 2015. This common share offering also includes an over-allotment option, exercisable within 30 days following the closing of the offering, for up to approximately an additional three million common shares that would provide additional gross proceeds of up to approximately $100 million. Enbridge has agreed to concurrently subscribe for approximately 5.3 million common shares (up to approximately six million common shares if the over-allotment option is exercised in full) on a private placement basis to maintain its 19.9% ownership interest in ENF.

Development Opportunities

The Canadian Liquids Pipelines business is expected to have future organic growth opportunities beyond the current inventory of secured projects. The Fund Group has a first right to execute any such projects that fall within the footprint of the Canadian Liquids Pipelines business. Should the Fund Group choose not to proceed with a specific growth opportunity, Enbridge may pursue such opportunity.

Economic Interest

Upon closing of the Transaction, Enbridge s overall economic interest in the Fund Group, including all of its direct and indirect interests in the Fund Group, was 91.9%. Upon completion of the $700 million common share issuance discussed above, Enbridge s economic interest is expected to decrease to 89.2%. As ENF executes on its financing plan and increases its ownership in the Fund Group over time, Enbridge s economic interest is expected to decline to approximately 80% by the end of 2018.

Fund Governance

Enbridge will continue to act as the manager of the Fund Group and operator and commercial developer of the Canadian Liquids Pipelines business. This will ensure continuity of management and operational expertise, with an ongoing commitment to the safe and reliable operation of the system. As a result of its significant ownership interest, Enbridge has the right to appoint a majority of the Trustees of the Board of ECT for as long as the Company holds a majority economic interest in the Fund Group. A standing conflicts committee has been established to review certain material transactions and arrangements where the interests of Enbridge, or its affiliates, and the relevant entity in the Fund Group, or its affiliates, come into conflict.

Alliance Pipeline Recontracting

During 2013, Alliance Pipeline announced a New Services Framework and the related tolls and tariff provisions required to implement the new services (collectively, New Services Framework) in which customers could express interest through a precedent agreement process. On June 30, 2015 and July 9, 2015, Alliance Pipeline received regulatory approval from the FERC and the National Energy Board (NEB), for the United States and Canadian segments of the pipeline, respectively, for this New Services Framework. Shipments under the New Services Framework will begin in December 2015. As part of its acceptance of Alliance Pipeline US New Services, the FERC set all issues related to the proposed elimination of Authorized Overrun Service and Interruptible Transportation revenue crediting, and the maintenance of Alliance Pipeline US existing recourse rates, for hearing. The negotiated reservation rates contained in the Precedent Agreements will be converted into negotiated rate transportation contracts as part of the New Services Offering and will not be part of this hearing. Alliance Pipeline has successfully re-contracted its firm capacity through 2018, and approximately 90% of receipt capacity in 2019 and 2020, with an average contract length of approximately five years.

Pursuant to the New Services Framework, Alliance Pipeline will retain exposure to potential variability in certain future costs and throughput volumes. As such, the majority of Alliance Pipeline s operations no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment and a derecognition of regulatory balances as at June 30, 2015 was required. The Fund Group recorded an after-tax write-down of approximately $10 million ($3 million after-tax attributable to Enbridge) during the second quarter of 2015.

SPONSORED INVESTMENTS ENBRIDGE ENERGY PARTNERS, L.P.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP s Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

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. On March 14, 2013, EEP received an order from the EPA (the Order) which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged the completion of the Order. In November of 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). The MDEQ has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, EEP reached a settlement with the MDEQ and the Michigan Attorney General s offices regarding the Line 6B crude oil release. As stipulated in the settlement, EEP agreed to: (1) provide at least 300 acres of wetland through restoration, creation or banked wetland credits to remain as wetland in perpetuity; (2) pay US$5 million as mitigation for impacts to the banks, bottomlands and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the river; (3) continue to reimburse the State of Michigan for costs arising from oversight of EEP activities since the release; and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of

Michigan.

As at September 30, 2015, EEP s cumulative cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($193 million after-tax attributable to Enbridge).

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2015. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois, caused by a third party water pipeline failure which damaged EEP s pipelineOne claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release. On February 20, 2015, Enbridge, EEP and their affiliates agreed to a consent order releasing the parties from any claims, liability or penalties.

Insurance

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP s remediation spending through September 30, 2015, 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 the existing insurance policy. As at September 30, 2015, 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 assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery of US$42 million from the other remaining insurers and amended its lawsuit such that it included only one insurer.

Of the remaining US$103 million coverage limit, US$85 million was the subject matter of a lawsuit Enbridge filed against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. The recovery of the remaining US$18 million is awaiting resolution of that arbitration which is not scheduled to occur until the fourth quarter of 2016. While the Company believes that those costs are eligible for recovery, there can be no assurance that it will prevail in the arbitration.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2016 with a liability program aggregate limit of US$860 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

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

As at September 30, 2015, included in EEP s estimated costs related to the Line 6B crude oil release is US$48 million in fines and penalties. Of this amount, US$40 million related to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. EEP has entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties and injunctive relief are ongoing.

In June 2015, EEP reached a separate agreement with the United States of America (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians and the Nottawaseppi Huron Band of the Potawatomi Indians to pay approximately US$3.9 million that EEP had accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

EEP Common Unit Issuance

In March 2015, EEP completed the issuance of eight million Class A Common Units for gross proceeds of approximately US$294 million before underwriting discounts and commissions and offering expenses. Enbridge did not participate in the issuance; however, the Company made a capital contribution of US$6 million to maintain its 2% general partner interest in EEP. EEP expects to use the proceeds from the offering to fund a portion of its capital expansion projects, for general partnership purposes or any combination of such purposes.

GROWTH PROJECTS COMMERCIALLY SECURED PROJECTS

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

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status

(Canadian dollars, unless stated otherwise)

LIQUIDS PIPELINES					
1.	Southern Access Extension	US$0.6 billion	US$0.4 billion	2015	Under construction
GAS DISTRIBUTION					
2.	Greater Toronto Area Project	$0.9 billion	$0.6 billion	2015-2016 (in phases)	Under construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
3.	Keechi Wind Project	US$0.2 billion	US$0.2 billion	2015	Complete
4.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-TBD (in phases)	Substantially complete
5.	Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	TBD	Substantially complete
6.	Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Under construction

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
7.	Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Under construction
8.	Stampede Oil Pipeline	US$0.2 billion	No significant expenditures to date	2018	Pre-construction
SPONSORED INVESTMENTS					
9.	The Fund Group - Eastern Access Line 9 Reversal and Expansion	$0.8 billion	$0.7 billion	2013-2015 (in phases)	Substantially complete
10.	The Fund Group - Canadian Mainline Expansion	$0.7 billion	$0.7 billion	2015	Complete
11.	The Fund Group - Surmont Phase 2 Expansion	$0.3 billion	$0.3 billion	2014-2015 (in phases)	Complete
12.	The Fund Group - Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.7 billion	2013-2015 (in phases)	Complete
13.	The Fund Group - Woodland Pipeline Extension	$0.7 billion	$0.7 billion	2015	Complete
14.	The Fund Group - Sunday Creek Terminal Expansion	$0.2 billion	$0.2 billion	2015	Complete
15.	The Fund Group - Edmonton to Hardisty Expansion	$1.8 billion	$1.4 billion	2015 (in phases)	Under construction
16.	The Fund Group - AOC Hangingstone Lateral	$0.2 billion	$0.1 billion	2015	Under construction
17.	The Fund Group - JACOS Hangingstone Project	$0.2 billion	$0.1 billion	2016	Under construction
18.	The Fund Group - Regional Oil Sands Optimization Project	$2.6 billion	$1.5 billion	2017	Under construction
19.	The Fund Group - Norlite Pipeline System3	$1.3 billion	$0.1 billion	2017	Under construction
20.	The Fund Group - Canadian Line 3 Replacement Program	$4.9 billion	$0.7 billion	2017	Pre-construction
21.	EEP - Eastern Access4	US$2.7 billion	US$2.3 billion	2013-2016 (in phases)	Under construction
22.	EEP - Lakehead System Mainline Expansion4	US$2.3 billion	US$1.9 billion	2014-2017 (in phases)	Under construction
23.	EEP - Beckville Cryogenic Processing Facility	US$0.2 billion	US$0.2 billion	2015	Complete
24.	EEP - Eaglebine Gathering	US$0.2 billion	US$0.1 billion	2015-2016 (in phases)	Under construction
25.	EEP - Sandpiper Project5	US$2.6 billion	US$0.7 billion	2017	Pre-construction
26.	EEP - U.S. Line 3 Replacement Program	US$2.6 billion	US$0.3 billion	2017	Pre-construction

1 *These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge s share of joint venture projects.*
2 *Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to September 30, 2015.*
3 *The Company will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.*
4 *The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.*
5 *The Company will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.*

LIQUIDS PIPELINES

Southern Access Extension

The Southern Access Extension joint venture involves the construction of a new 265-kilometre (165-mile), 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 barrels per day (bpd), as well as additional tankage and two new pump stations. The project is expected to be placed into service in the fourth quarter of 2015.

The Company s share of

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the estimated capital cost is expected to be approximately US$0.6 billion, with expenditures to date of approximately US$0.4 billion.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD is undertaking the expansion of its natural gas distribution system in the Greater Toronto Area (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 involves the construction of two new segments of pipeline, a 27-kilometre (17-mile), 42-inch diameter pipeline (Western segment) that is expected to enter service in the first quarter of 2016 and a 23-kilometre (14-mile), 36-inch diameter pipeline (Eastern segment) that is expected to enter service in December of 2015 as well as related facilities to upgrade the existing distribution system in Toronto, Ontario, that delivers natural gas to several municipalities in Ontario. Construction began in January 2015. The project is now expected to cost approximately $0.9 billion due to greater complexity in the construction and requirements from government and permitting agencies. Expenditures incurred to date were approximately $0.6 billion.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Keechi Wind Project

In 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-megawatt Keechi Wind Project (Keechi), located in Jack County, Texas. The project was constructed by RES Americas under a fixed price, engineering, procurement and construction agreement at a total cost of approximately US$0.2 billion, and it entered service in January 2015. The electricity generated by Keechi is delivered into the Electric Reliability Council of Texas, Inc. market under a 20-year power purchase agreement with Microsoft Corporation.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, the Company is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the Chevron operated Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 metres (7,000 feet), with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS was placed into service in December 2014. The Big Foot portion of the WRGGS start-up has been delayed due to platform installation issues experienced by Chevron. Chevron is currently investigating the extent of the damage and the delay. The Big Foot gas portion of the WRGGS has met its completion requirements under the terms of the agreements and the Company expects to begin collecting take or pay toll revenue in the fourth quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., the Company is constructing a 64-kilometre (40-mile), 20-inch oil pipeline with a capacity of 100,000 bpd from Chevron s Big

Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to the Company s undertaking of the WRGGS construction, discussed above. Upon completion of the project, the Company will operate the Big Foot Oil Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. As noted above, although the Big Foot ultra-deep water development has been delayed, the Big Foot Oil Pipeline has met its completion requirements under the terms of the agreements and the Company expects to begin collecting take or pay revenue in the fourth quarter of 2015. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.2 billion.

Aux Sable Extraction Plant Expansion

In 2014, the Company approved the expansion of fractionation capacity and related facilities at the Aux Sable Extraction Plant located in Channahon, Illinois. The expansion will facilitate the growing NGL-rich gas stream on the Alliance Pipeline, allow for effective management of Alliance Pipeline s downstream natural gas heat content and support additional production and sale of NGL products. The expansion is expected to be placed into service in the second quarter of 2016, with the Company s share of the project cost being approximately US$0.1 billion.

Heidelberg Oil Pipeline

The Company will construct, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation, to an existing third party system. Heidelberg Oil Pipeline (Heidelberg Pipeline), a 58-kilometre (36-mile), 20-inch diameter pipeline with capacity of 100,000 bpd, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana and in an estimated 1,600 metres (5,300 feet) of water. Heidelberg Pipeline is expected to be operational in the second quarter of 2016 at an approximate cost of US$0.1 billion, with expenditures to date of approximately US$0.1 billion.

Stampede Oil Pipeline

In January 2015, Enbridge announced that it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the planned Stampede development, which is operated by Hess Corporation, to an existing third party pipeline system. The Stampede Oil Pipeline (Stampede Pipeline), a 26-kilometre (16-mile), 18-inch diameter pipeline with capacity of approximately 100,000 bpd, will originate in Green Canyon Block 468, approximately 350 kilometres (220 miles) southwest of New Orleans, Louisiana, at an estimated depth of 1,200 metres (3,900 feet). Stampede Pipeline is expected to be completed at an approximate cost of US$0.2 billion and is expected to be placed into service in 2018.

SPONSORED INVESTMENTS

As part of the Canadian Restructuring Plan, the commercially secured growth programs embedded within EPI and EPAI were transferred to the Fund Group and are now presented in Sponsored Investments. Enbridge continues to oversee the execution of the growth program, as well as manage the operations and future development opportunities of these assets. Reference to the Company in this Sponsored Investments section includes activities performed by the Fund Group, or on its behalf by Enbridge, following the completion of the Canadian Restructuring Plan.

The Fund Group

Eastern Access

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by the Company include a reversal of Line 9A and expansion of the Toledo Pipeline, both completed in 2013, as well as the reversal of Line 9B and expansion of Line 9 (together, Line 9). For discussion on EEP s portion of Eastern Access, refer to *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Eastern Access*.

The Company is undertaking a reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in that province. The Line 9B reversal was initially expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity into Ontario and Quebec, resulting in the Line 9 capacity expansion project. The Line 9 capacity expansion will increase the annual capacity of Line 9 from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

The Line 9B Reversal and Line 9 Capacity Expansion projects were approved by the NEB in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B Reversal and Line 9 Capacity Expansion Project. On October 23, 2014, the Company responded to the NEB describing the Company s rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB s order requiring approval, and the Company filed for a Leave to Open (LTO), which is a prerequisite to allowing the operation of the project. In its February approval, the NEB also imposed additional obligations on the Company that directed the Company to take a life-cycle approach to water crossings and valves, requiring it to perform ongoing analysis to ensure optimal protection of the area s water resources. On June 18, 2015, the NEB approved the LTO application and issued a separate order imposing further conditions requiring the Company to perform hydrostatic tests of selected segments of the pipeline. The Company filed its hydrostatic test plan with the NEB on July 23, 2015, which was approved on July 27, 2015. Hydrostatic testing was completed and the Company submitted the test results to the NEB in September 2015. On September 30, 2015 the NEB confirmed that the hydrostatic tests successfully met their criteria. Line-fill commenced in late October 2015 and the pipeline is expected to be placed into service in December 2015.

Cost estimates related to conditions imposed by the NEB, including valve placement and hydrostatic testing, are expected to increase the total project cost to $0.8 billion, inclusive of costs related to the previously mentioned Line 9A reversal. Pursuant to various agreements with shippers, the Company expects to recover from shippers the full costs of compliance with NEB imposed hydrostatic testing. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.7 billion.

On July 31, 2014, the Company filed an application for tolls on Line 9. After complaints from shippers on Line 9 were filed with the NEB with respect to the inclusion of mainline surcharges in the Line 9 toll, the NEB approved the tolls on an interim basis to allow for time to engage shippers in further discussions to attempt to resolve the outstanding issues. On January 30, 2015, the NEB convened a hearing to consider the matter. In response to a request from the Company that was supported by the shippers, the hearing was suspended to allow the Company and shippers to engage in further discussions to resolve the outstanding issues. In the third quarter of 2015, the Company and the shippers came to an agreement to recover mainline surcharges in the Line 9 toll.

Canadian Mainline Expansion

The Company undertook an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consisted of two phases that involved the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was completed in the third quarter of 2014 at an estimated capital cost of approximately $0.2 billion. The second phase to increase capacity from 570,000 bpd to 800,000 bpd was completed in July 2015 at an expected cost of approximately $0.5 billion. The total cost of the entire expansion was approximately $0.7 billion. Receipt of the final regulatory approval on EEP s portion of the mainline system expansion has been delayed. EEP continues to work with regulatory authorities; however, the timing of the federal regulatory approval 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 this delay. See *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Mainline Expansion*.

Surmont Phase 2 Expansion

In 2013, the Company entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. (ConocoPhillips) and Total E&P Canada Ltd. (together, the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont s Phase 2 expansion. The Company constructed two new 450,000 barrel blend tanks and converted an existing tank from blend to diluent service. The expansion occurred in two phases with the blended product system placed into service in November 2014 and the diluent system placed into service in March 2015 at a total cost of approximately $0.3 billion.

Canadian Mainline System Terminal Flexibility and Connectivity

As part of the Light Oil Market Access Program initiative, the Company undertook the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The modifications comprised of upgrading existing booster pumps, installing additional booster pumps and adding new tank line connections. These projects had varying completion dates from 2013 through the second quarter of 2015. The total cost of the project was approximately $0.7 billion.

Woodland Pipeline Extension

The joint venture Woodland Pipeline Extension Project extends the Woodland Pipeline south from the Company s Cheecham Terminal to its Edmonton Terminal. The extension is a 388-kilometre (241-mile), 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. The project was completed and placed into service in July 2015. The Company s share of the project costs is approximately $0.7 billion.

Sunday Creek Terminal Expansion

In 2014, the Company announced the construction of additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion included development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The project was placed into service in August 2015 at an approximate cost of $0.2 billion.

Edmonton to Hardisty Expansion

The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project includes 181 kilometres (112 miles) of new 36-inch diameter pipeline and will provide an initial capacity of approximately 570,000 bpd, expandable to 800,000 bpd. The new line generally follows the same route as the Company s existing Line 4 pipeline. Also included in the project scope are connections into existing infrastructure at the Hardisty Terminal and new terminal facilities in Edmonton, Alberta which include five new 500,000 barrel tanks. The new pipeline was placed into service in April 2015, with additional tankage requirements expected to be completed by the fourth quarter of 2015. The total cost of the project is expected to be approximately $1.8 billion, with expenditures to date of approximately $1.4 billion.

AOC Hangingstone Lateral

In 2013, the Company entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminalling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Phase I of the project will involve the construction of a new 49-kilometre (31-mile), 16-inch diameter pipeline from the AOC Hangingstone project site to the Company s existing Cheecham Terminal and related facility modifications at Cheecham, Alberta. This phase of the project will provide an initial capacity of 16,000 bpd and is expected to be placed into service in the fourth quarter of 2015 at an estimated cost of approximately $0.2 billion. Expenditures to date on the project are approximately $0.1 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

JACOS Hangingstone Project

The Company will undertake the construction of facilities and provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). JACOS and Nexen Energy ULC, a wholly-owned subsidiary of China National Offshore Oil Corporation Limited, are partners in the project which is operated by JACOS. The Company plans to construct a new 53-kilometre (33-mile), 12-inch lateral pipeline to connect the JACOS Hangingstone project site to the Company s existing Cheecham Terminal. The project, which will provide capacity of 40,000 bpd, is expected to enter service in 2016. The estimated cost is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion.

Regional Oil Sands Optimization Project

In March 2015, the Company announced a plan to optimize previously announced expansions of its Regional Oil Sands System currently in execution. The Company previously announced the Wood Buffalo Extension, which includes the construction of a 30-inch pipeline, from the Company s Cheecham Terminal to its Battle River Terminal at Hardisty, Alberta and associated terminal upgrades, and the Athabasca Pipeline Twin, which consists of the twinning of the southern section of the Athabasca Pipeline with a 36-inch diameter pipeline from Kirby Lake, Alberta to its Hardisty crude oil hub.

The optimization plan, which has been agreed to with the affected shippers, including Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), will enable deferral of the southern segment of the Wood Buffalo Extension by connecting it to the Athabasca Pipeline Twin. The optimization involves the upsize of a 100-kilometre (60-mile) segment of the Wood Buffalo Extension between Cheecham, Alberta and Kirby Lake, Alberta from a 30-inch diameter pipeline to a 36-inch diameter pipeline, which will now connect to the origin of the Athabasca Pipeline Twin at Kirby Lake, Alberta. The capacity of the Athabasca Pipeline Twin will be expanded from 450,000 bpd to 800,000 bpd through additional horsepower.

The definitive cost estimate of the Wood Buffalo Extension was finalized at approximately $1.8 billion before optimization. As a result of the optimization, the cost estimate to complete the integrated Wood Buffalo Extension and Athabasca Pipeline Twin projects is expected to decrease from approximately $3.0 billion to approximately $2.6 billion. Expenditures on the joint projects to date are approximately $1.5 billion.

The integrated Wood Buffalo Extension and Athabasca Pipeline Twin will transport diluted bitumen from the proposed Fort Hills Partners oil sands project (Fort Hills Project) in northeastern Alberta, as well as from oil sands production from Suncor Energy Oil Sands Limited Partnership (Suncor Partnership) in the Athabasca region. The Wood Buffalo Extension and the Athabasca Pipeline Twin will ship blended bitumen from the Fort Hills Project and have an expected 2017 in-service date. The Athabasca Pipeline Twin will also ship blended bitumen from the Cenovus Christina Lake Steam Assisted Gravity Drainage project near the origin of the Athabasca Pipeline Twin.

Norlite Pipeline System

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. The scope of the project was increased to a 24-inch diameter pipeline, which will provide an initial capacity of approximately 224,000 bpd of diluent, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. Norlite will be anchored by throughput commitments from the Fort Hills Partners for production from the proposed Fort Hills Project and from Suncor Partnership s proprietary oil sands production. Norlite will involve the construction of a new 449-kilometre (278-mile) pipeline from the Company s Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership s East Tank Farm, which is adjacent to the Company s existing Athabasca Terminal. Under an agreement with Keyera Corp. (Keyera), Norlite has the right to access certain existing capacity on Keyera s pipelines between Edmonton, Alberta and Stonefell, Alberta and, in exchange, Keyera has elected to participate in the new pipeline infrastructure project as a 30% non-operating owner. Subject to regulatory and other approvals, Norlite is expected to be completed in 2017 at an estimated cost of approximately $1.3 billion, with expenditures to date of approximately $0.1 billion.

Canadian 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 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. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system, enhance flexibility and allow the Company to optimize throughput on the mainline system s overall western Canada export capacity. The L3R Program is expected to achieve capacity of approximately 760,000 bpd.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in late 2017. The NEB deemed the Canadian Line 3R Program application complete and issued a hearing order in which it confirmed that it had until May 2016 to issue a decision. The Company has reached a settlement agreement with landowner associations representing Line 3 landowners in Canada and as a result these parties have withdrawn from the hearing process.

The estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.7 billion. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (CTS). For discussion on EEP s portion of the L3R Program, refer to *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. United States Line 3 Replacement Program*.

Enbridge Energy Partners, L.P.

Eastern Access

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects undertaken by EEP include an expansion of Line 5 and of the United States mainline involving the Spearhead North Pipeline (Line 62), both completed in 2013, and replacement of additional segments of Line 6B, completed in 2014. The cost of these projects is approximately US$2.4 billion. For discussion on the Company s portion of Eastern Access, refer to *Growth Projects Commercially Secured Projects Sponsored Investments The Fund Group Eastern Access*.

Additionally, the Eastern Access initiative also includes a further upsizing of EEP s Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan will increase capacity from 500,000 bpd to 570,000 bpd and will include pump station modifications at the Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. The Line 6B capacity expansion is now expected to be placed into service in mid-2016 at an estimated cost of approximately US$0.3 billion.

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative, including the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$2.3 billion. The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to Enbridge Energy, Limited Partnership (EELP) for its interests in the Eastern Access projects until the second quarter of 2016. EELP holds partnership interest in assets that are jointly funded by Enbridge and EEP, including the Eastern Access projects. In return, Enbridge s capital funding contribution requirements to the Eastern Access projects will be netted against its foregone cash distribution during this period.

Lakehead System Mainline Expansion

The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and include the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61) and the construction of the Spearhead North Twin (Line 78).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase increased capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase increased capacity from 570,000 bpd to 800,000 bpd at an estimated capital cost of approximately US$0.2 billion. The initial phase was completed in the third quarter of 2014 and the second phase was completed in July 2015. Both phases of the Alberta Clipper expansion required only the addition of pumping horsepower with no pipeline construction and are subject to regulatory approvals, including 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. EEP continues to work with regulatory authorities; however, 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.

In November 2014, several environmental and Native American groups filed a complaint in the United States District Court in Minnesota against the United States Department of State (DOS). The Complaint alleges, among other things, that the DOS is in violation of the United States National Environmental Policy Act by acquiescing in the Company s use of permitted cross border capacity on other pipelines to achieve the transportation of amounts in excess of Alberta Clipper s current permitted capacity while the review and approval of the Company s application to the DOS to increase Alberta Clipper s permitted cross border capacity is still pending. The Company has intervened in the case and a decision at the trial level is not expected before the fourth quarter of 2015.

The scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of phases that require only the addition of pumping horsepower with no pipeline construction. The initial phase to increase the capacity from 400,000 bpd to 560,000 bpd was completed in August 2014 at an estimated capital cost of approximately US$0.2 billion. EEP further expanded the pipeline capacity to 800,000 bpd in May 2015 at an estimated capital cost of approximately US$0.4 billion. Additional tankage is expected to cost approximately US$0.4 billion and will be completed on various dates beginning in the third quarter of 2015 through the third quarter of 2016. In the first quarter of 2015, the Company, in conjunction with shippers, decided to delay the in-service date of a further expansion tranche to increase the pipeline capacity to 1,200,000 bpd at an estimated capital cost of approximately US$0.4 billion, to align more closely with the currently anticipated in-service date for the Sandpiper Project (Sandpiper). In October 2015, a portion of this tranche was put into service early to address capacity constraints, increasing the pipeline capacity to 950,000 bpd. The remaining capacity is expected to be in service in late 2017.

As part of the Light Oil Market Access Program, EEP also plans to expand the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 127-kilometre (79-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62). The project is expected to be completed at an estimated cost of approximately US$0.5 billion. The new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in the fourth quarter of 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$1.9 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. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to EELP for its interests in the Lakehead System Mainline Expansion until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Lakehead System Mainline Expansion. In return, Enbridge s capital funding contribution requirements to the Lakehead System Mainline Expansion will be netted against its foregone cash distribution during this period.

Beckville Cryogenic Processing Facility

EEP and its partially-owned subsidiary, MEP, have constructed a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant offers incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a natural gas processing capability of 150 mmcf/d and is expected to produce 8,500 bpd of NGL. The Beckville Plant was placed into service in May 2015 at a cost of approximately US$0.2 billion.

Eaglebine Gathering

In February 2015, EEP and MEP announced they are entering into the emerging Eaglebine shale play in East Texas through two transactions totalling approximately US$0.2 billion. EEP and MEP have commenced construction of the Ghost Chili pipeline project, which consists of a lateral and associated facilities that will create gathering capacity of over 50 mmcf/d for rich natural gas to be delivered from Eaglebine production areas to their complex of cryogenic processing facilities in East Texas. The initial facilities were placed into service in October 2015. EEP also expects to construct the Ghost Chili

Extension Lateral by late 2016 to fully utilize the gathering capacity with the rest of EEP s processing assets. MEP also acquired New Gulf Resources, LLC s midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation. Expenditures incurred to date are approximately US$0.1 billion.

Sandpiper Project

As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper, which will expand and extend EEP s North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline. Sandpiper is expected to cost approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.7 billion.

EEP is in the process of obtaining the appropriate permits for constructing Sandpiper in Minnesota. The project requires both a Certificate of Need and Route Permit from the Minnesota Public Utilities Commission (MNPUC). On August 3, 2015, the MNPUC issued an order granting a Certificate of Need and a separate order restarting the Route Permit proceedings. On September 14, 2015 the Minnesota Court of Appeals reversed the MNPUC s Certificate of Need order stating that an Environmental Impact Statement must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. As of October 7, 2015 the MNPUC stayed its August 3, 2015 order and reopened the Certificate of Need proceeding. Both the MNPUC and EEP have appealed the Minnesota Court of Appeals decision to the State Supreme Court. Activity continues in the Route Permit proceeding according to MNPUC expectations. Subject to regulatory and other approvals, the expected in-service date for Sandpiper is late 2017.

Marathon Petroleum Corporation (MPC) has been secured as an anchor shipper for Sandpiper. As part of the arrangement, EEP, through its subsidiary, North Dakota Pipeline Company LLC (NDPC) (formerly known as Enbridge Pipelines (North Dakota) LLC), and Williston Basin Pipeline LLC (Williston), an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of Sandpiper construction and will have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed US$1.2 billion in aggregate. In return for funding part of Sandpiper s construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper.

United States Line 3 Replacement Program

In 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. EEP will undertake the United States portion of the Line 3 Replacement Program (U.S. L3R Program) which 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. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system, enhance flexibility and allow the Company to optimize throughput on the mainline system s overall western Canada export capacity. The L3R Program is expected to achieve capacity of approximately 760,000 bpd.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in late 2017. The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. The MNPUC has sent the Certificate of Need application to the ALJ for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Court of Appeals decision in the Sandpiper docket, the ALJ has requested direction on how to proceed with the

Certificate of Need process for Line 3. The Company filed a motion to join the Certificate of Need and Route Permit dockets which would enable the MNPUC to rely on the Comparative Environmental Analysis in reaching its decision on both the Certificate of Need and Route Permit applications.

The estimated capital cost of the U.S. L3R Program is approximately US$2.6 billion, with expenditures to date of approximately US$0.3 billion. 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.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met the Company s criteria to be classified as commercially secured. The Company also has significant additional attractive projects under development that have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

LIQUIDS PIPELINES

Northern Gateway Project

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

In June 2014, the Governor in Council approved Northern Gateway, subject to 209 conditions following a recommendation from the Joint Review Panel (JRP). The Company continues to work closely with its customers in advancing this project to open West Coast market access and is making progress in fulfilling the conditions and building relationships and trust with communities and Aboriginal groups along the proposed route.

Nine applications to the Federal Court of Appeal (Federal Court) for leave for judicial review of the Order in Council have been filed pursuant to section 55 of the NEB Act. The applicants make two basic arguments in seeking leave. First, they argue that the JRP report and the Order in Council contain evidentiary gaps or gaps in reasoning. Second, they allege that the Crown has failed to discharge its constitutional duty to consult and, if appropriate, accommodate the Aboriginal applicants.

On September 26, 2014, the Federal Court granted leave to all nine applications and on December 17, 2014, the Federal Court issued a decision accepting the request by all parties to consolidate the nine applications into a single proceeding (the Application) and stated that delays in the hearing of the Application should be minimized. The filing of the Appellants Memoranda of Fact and

Law occurred in May 2015 and the Respondents Memoranda were filed in June 2015. The hearing of the Application commenced in Vancouver on October 1, 2015 and concluded on October 8, 2015. Depending on the outcome of these proceedings, which is anticipated for 2016, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

The Company reviewed an updated cost estimate of Northern Gateway based on full engineering analysis of the pipeline route and terminal location. Based on this comprehensive review, the Company expects that the final cost of the project will be substantially higher than the preliminary cost figures included in the Northern Gateway filing with the JRP, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the

Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. The updated cost estimate is currently being assessed and refined by Northern Gateway and the potential shippers. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.5 billion, of which approximately half is being funded by potential shippers on Northern Gateway.

The in service date of the project will be dependent upon the timing and outcome of judicial reviews, continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities). Of the 48 Aboriginal groups eligible to participate as equity owners, 28 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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Canadian Mainline	**109**	128	**395**	400
Regional Oil Sands System	**17**	44	**108**	134
Seaway and Flanagan South Pipeline	**41**	16	**63**	