ENBRIDGE INC
Form 6-K
May 06, 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 May 6, 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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:

- Press Release dated May 6, 2015.
- Interim Report to Shareholders for the three months ended March 31, 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: May 6, 2015

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

Vice President & Corporate Secretary

NEWS RELEASE

Enbridge reports first quarter adjusted earnings of $468 million or $0.56 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

- First quarter loss was $383 million, including the impact of net unrealized non-cash mark-to-market losses
- First quarter adjusted earnings were $468 million or $0.56 per common share
- Expansion of the Canadian Mainline system between Edmonton and Hardisty placed into service in April
- Enbridge delivered a formal proposal to transfer the majority of its Canadian Liquids Pipelines business and certain renewable energy assets to Enbridge Income Fund
- Enbridge announced a plan to optimize previously announced expansions of its Regional Oil Sands System
- Enbridge announced it will build, own and operate the Stampede Oil Pipeline to the planned Stampede development in the Gulf of Mexico
- Effective March 1,2015, Enbridge quarterly common share dividend increased by 33% over the last year to an annual rate of $1.86 per share

CALGARY, ALBERTA May 6, 2015 Enbridge Inc. (Enbridge or the Company) (TSX:ENB) (NYSE:ENB) Enbridge delivered a solid first quarter of 2015, reflecting a combination of strong asset performance and the ongoing successful execution of our growth capital program, said Al Monaco, President and Chief Executive Officer. Adjusted earnings for the first quarter of 2015 were $468 million or $0.56 per common share.

Our results were in line with our expectations, and we remain on track to deliver full year adjusted earnings per share within our guidance range of $2.05 to $2.35, Mr. Monaco said. Our resilient business model continues in the current business environment to deliver reliable and predictable earnings and cash flows to our investors.

Throughput on Enbridge s liquids mainline remained strong. Over the first quarter our systems were very highly utilized, shipping an average 2.2 million barrels per day across the Canada/United States border, Mr. Monaco added. We are now seeing the benefit of our system optimization through record volumes on our mainline. The full benefits of those efforts will be seen over the course of 2015.

Enbridge continues to deliver solid earnings and strong returns to our shareholders. However, low commodity prices are challenging for our customers, so we are keenly focused on providing low cost, reliable transportation to the best markets for them, Mr. Monaco said. We are pleased that stable tolls and our capacity optimization and market access initiatives that took place through 2014 are helping producers to maximize their netbacks and provide reliable feedstock for refiners.

Forward-Looking Information and Non-GAAP Measures

This news release contains forward-looking information and references to non-GAAP measures. Significant related assumptions and risk factors, and reconciliations are described under the Forward-Looking Information and Non-GAAP Measures sections of this news release, respectively.

Enbridge achieved key milestones on two of its liquids pipelines growth projects since reporting its year end results in February. During April, the Company brought into service on schedule and under budget a new 36-inch, 181-kilometre (112-mile) pipeline connecting its Edmonton and Hardisty Terminals. The $1.8 billion pipeline is a significant addition to the Company s mainline system and will initially have capacity to transport up to 570,000 barrels per day (bpd), but can be readily expanded to 800,000 bpd.

On April 13, 2015, a Minnesota Administrative Law Judge (ALJ) recommended that the Minnesota Public Utility Commission grant a Certificate of Need permit for the Company s proposed Sandpiper Pipeline Project (Sandpiper). The 965-kilometre (600-mile), US$2.6 billion project will transport Bakken crude from Enbridge s Beaver Lodge Station, south of Tioga, North Dakota, to Clearbrook, Minnesota through a 24-inch diameter pipeline. A 30-inch diameter pipeline will connect Clearbrook to Superior, Wisconsin. Subject to regulatory approval, the pipeline is expected to begin service in 2017. A review of the proposed pipeline route will follow a decision on the Certificate of Need.

As we have said, our primary goal with this project is to ensure public safety and environmental protection. The ALJ recommendation is a positive step forward, and a reflection of the hard work our team did engaging communities, listening to people and addressing their concerns. We also thank the numerous stakeholders for their support of the project and helping us to make this an even better project, said Mr. Monaco. Sandpiper is an important project for Bakken shippers and will add much needed pipeline capacity to enable them to reach key markets and improve netbacks.

Looking ahead, our commercially secured portfolio of growth projects remains secure and is on track for execution, Mr. Monaco said. We are positive on the longer-term fundamentals supporting our businesses and the development of infrastructure that our customers require and believe we are well positioned to continue to deliver industry leading earnings and dividend growth through 2018 and beyond. Our growth will continue to be supported by a disciplined approach to investment and project execution and attention to our number one priority the safety and reliability of our systems.

In February, the National Energy Board (NEB) approved Conditions 16 and 18 of Enbridge s application for the reversal and expansion of Line 9B. The Company subsequently applied to the NEB for a Leave to Open to commence operation of the project. The pipeline is mechanically complete and awaiting the NEB s final approval.

Line 9B is critical to ensuring that eastern Canadian refiners have access to reliable and cost effective feedstock and assuring the competitiveness of eastern Canada s petrochemical industry, said Mr. Monaco.

On March 31, 2015, Enbridge delivered a formal proposal (the Canadian Restructuring Plan) to a committee of independent members of the boards of Enbridge Commercial Trust (ECT) and Enbridge Income Fund Holdings Inc. (ENF) to transfer Enbridge s Canadian Liquids Pipelines business and certain renewable energy assets to Enbridge Income Fund (the Fund). The transaction is anticipated to provide Enbridge with low-cost funding to support the enterprise-wide $44 billion growth capital program and is expected to be accretive to adjusted earnings per share by approximately 10% per year on average from 2015 to 2018.

The transaction is also expected to transform the Fund and ENF through the acquisition of high quality assets that come with embedded growth. ENF s dividend is expected to increase by approximately 10% on closing, and by a further 10% at the beginning of 2016 and each year thereafter through to 2019. In conjunction with the Canadian Restructuring Plan, the Company also increased its quarterly common share dividend by 33% effective March 1, 2015 and introduced a new dividend payout policy range of 75% to 85% of adjusted earnings.

This transaction is expected to deliver significant value to investors of both Enbridge and Enbridge Income Fund Holdings and it will even better position us to extend our industry-leading growth beyond 2018, added Mr. Monaco. We expect the transaction to close mid-2015.

Operations

Adjusted earnings for the first quarter of 2015 were $468 million, or $0.56 per common share, compared with adjusted earnings of $492 million, or $0.60 per common share, for the first quarter of 2014.

In Liquids Pipelines, the throughput trends experienced in 2014 continued into the first quarter of 2015 and resulted in record throughput on Canadian Mainline. Furthermore, the impact of a strong United States dollar, which had a hedged and an unhedged component, compared with the Canadian dollar had a positive impact on Canadian Mainline earnings as the International Joint Tariff Benchmark (IJT) Toll and its components are set in United States dollars. However, these factors were more than offset by a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher due to the recovery of incremental costs associated with EEP s growth projects. Growing volumes on the system, together with the impact of an increase to the Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions are expected to drive strong revenue and earnings growth over the balance of 2015.

Within Sponsored Investments, Enbridge Energy Partners, L.P. (EEP) and the Fund both had strong first quarters of 2015, with each reflecting the favourable impact of drop downs from Enbridge. EEP adjusted earnings reflected higher volumes and tolls in its liquids business, as well as new assets placed into service. EEP earnings also reflected the incremental earnings from the acquisition of the 66.7% interest in Alberta Clipper previously held by Enbridge. The earnings increase from the Fund was attributable to the transfer of natural gas and diluent pipeline interests from Enbridge and higher preferred unit distributions received from the Fund.

Enbridge Gas Distribution Inc. (EGD) continued to deliver reliable results in the first quarter, although earnings were lower than the comparative period in 2014 due to the application of lower interim distribution rates in the first quarter of 2015. Any shortfall in revenues arising from the difference between interim and final 2015 rates will be recovered during 2015 and will not have an impact on full year results which are expected to be higher than the prior year.

Adjusted earnings were also impacted by higher preference share dividends in the Corporate segment, as well as higher interest expense across various business segments reflecting incremental preference share and debt issued to fund the Company s growth capital program.

The adjusted earnings discussed above exclude the impact of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains and losses from the Company s long-term hedging program. See *Non-GAAP Measures.*

FIRST QUARTER 2015 OVERVIEW

For more information on Enbridge s growth projects and operating results, please see the Management s Discussion and Analysis (MD&A) which is filed on SEDAR and EDGAR and also available on the Company s website at www.enbridge.com/InvestorRelations.aspx.

- Loss attributable to common shareholders were $383 million in the first quarter of 2015 compared with earnings of $390 million in the first quarter of 2014. The Company delivered solid results from operations in the first quarter of 2015; however, the visibility and comparability of the 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 that over the long-term it supports the reliable cash flows and dividend growth upon which the Company s investor value proposition is based. Other factors impacting the comparability of period-over-period earnings 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, as well as insurance recoveries of $9 million after-tax related to the Line 37 crude oil release which occurred in June 2013.

- Enbridge s adjusted earnings for the first quarter of 2015 and 2014 were $468 million and $492 million, respectively. Liquids Pipelines adjusted earnings decreased as the positive effects of higher throughput, higher terminalling revenues, a favourable United States/Canada foreign exchange rate and lower income taxes on Canadian Mainline were more than offset by a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll and higher operating and administrative expense. On April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased from US$1.53 per barrel to US$1.63 per barrel. Growing volumes on the system, together with the impact of a higher Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions as they come into service, including surcharges for the recently completed Edmonton to Hardisty Expansion, are expected to drive strong revenues and earnings growth over the balance of 2015. In Gas Distribution, EGD adjusted earnings decreased in the first quarter of 2015 due to lower interim distribution rates applicable in the first quarter of 2015 compared with the interim rates applicable in the corresponding 2014 period. EGD expects to collect and record the difference between the interim rates and applicable 2015 rates during 2015. Positively impacting adjusted earnings in Gas Distribution was the absence of a loss that Enbridge Gas New Brunswick Inc. 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 Sponsored Investments, EEP adjusted earnings reflected higher throughput and tolls on its liquids business, as well as the impact of new assets placed into service in 2014. EEP adjusted earnings also reflected the incremental earnings from the acquisition of the remaining 66.7% interest of Alberta Clipper previously held by Enbridge. Higher contribution from EEP also reflected distributions from Class D units which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued in January 2015 in connection with the transfer of Alberta Clipper. The Fund benefitted from the transfer of natural gas and diluent pipeline interests from Enbridge. Higher preferred unit distributions received by Enbridge from the Fund also provided an increase to adjusted earnings. Finally, within the Corporate segment, higher preference share dividends arising from an increase in the number of preference shares in 2014 to fund the Company s growth capital program negatively impacted adjusted earnings.

- On March 31, 2015, Enbridge announced it had delivered a formal proposal to a committee of independent members of the boards of ECT and ENF to transfer Enbridge s Canadian Liquids Pipelines business, comprised of Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., along with certain renewable energy assets, with a combined carrying value of approximately $17 billion and an associated secured growth capital program of approximately $15 billion, to the Fund. The formal proposal follows the Company s December 3, 2014 announcement of the proposed Canadian Restructuring Plan. The general terms and projected financial outcomes of the proposed transfer are substantially consistent with those originally described in that announcement. The transfer also remains subject to approval by the boards of ECT and ENF, following a recommendation by a joint special committee.

- Effective, March 15, 2015, the Enbridge Board of Directors appointed Rebecca B. Roberts as a director. Ms. Roberts is the former President of Chevron Pipe Line Company and Chevron Global Power Generation and is currently a director of MSA Safety Incorporated and Black Hills Corporation. Ms. Roberts was previously also a director of Enbridge Energy Management, L.L.C. and Enbridge Energy Company, Inc., the general partner of EEP.

- On March 5, 2015, the Company announced a plan to optimize previously announced expansions of its Regional Oil Sands System currently in execution. 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

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will now connect to the origin of the Athabasca Pipeline Twin at Kirby Lake, Alberta. The capacity of the Athabasca Pipeline Twin would 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. Along with the Company s Norlite Pipeline System, the Wood Buffalo Extension and the Athabasca Pipeline Twin will be the conduit to ship diluent to, and blended bitumen from, the proposed Fort Hills Partners oil sands project which has an expected 2017 in-service date.

- On January 12, 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. 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 (3,500 feet). After finalization of scope and a definitive cost estimate, 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.

DIVIDEND DECLARATION

On May 5, 2015, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2015 to shareholders of record on May 15, 2015.

Common Shares	$0.46500
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500

CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, May 6, 2015 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the first quarter 2015 results. Analysts, members of the media and other interested parties can access the call toll-free at 1-800-708-4539 from within North America and outside North America at 1-847-619-6396, using the access code of 39285337#. The call will be audio webcast live at http://edge.media-server.com/m/p/88t4gnim/lan/en. A webcast replay and podcast will be available approximately two hours after the conclusion of the event and a transcript will be posted to the website within 24 hours. The replay will be available toll-free at 1-888-843-7419 within North America and outside North America at 1-630-652-3042 (access code 39285337#) until May 13, 2015.

The conference call will begin with presentations by the Company s President and Chief Executive Officer and the Chief Financial Officer, followed by a question and answer period for investment analysts. A question and answer period for members of the media will then immediately follow.

Enbridge, a Canadian Company, is a North American leader in delivering energy and has been included on the Global 100 Most Sustainable Corporations in the World ranking for the past seven years. As a transporter of energy, Enbridge operates, in Canada and the United States, the World s longest crude oil and liquids transportation system. The Company also has significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada s largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in more than 2,200 megawatt (MW) (1,600 MW net) of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal facilities. Enbridge employs more than 11,000 people, primarily in Canada and the United States and is ranked as one of Canada s Top 100 Employers for 2015. Enbridge s common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit www.enbridge.com. None of the information contained in, or connected to, Enbridge s website is incorporated in or otherwise part of this news release.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this news release to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge s 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 , believe and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; 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; the Canadian Restructuring Plan; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; 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; final approval of definitive transfer terms by Enbridge and ENF and the Fund with respect to the Canadian Restructuring Plan; receipt of all necessary shareholder and regulatory approvals that may be required for the Canadian Restructuring Plan; and weather. 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) or adjusted earnings/(loss) and associated per share amounts, the impact of the Canadian Restructuring Plan on Enbridge, the adjusted dividend payout policy 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 Canadian Restructuring Plan, revised dividend policy, adjusted earning guidance, 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 news release 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 news release 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 news release contains references to non-GAAP measures, including adjusted earnings/(loss), which represent 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 in the Company s MD&A. 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. Management believes the presentation of non-GAAP measures such as adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company s dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by accounting principles generally accepted in the United States of America (U.S. GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. The table below summarizes the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Earnings/(loss) attributable to common shareholders	**(383)**	390
Adjusting items[1]:		
Changes in unrealized derivative fair value loss[2]	**977**	190
Make-up rights adjustments	**4**	2
Leak insurance recoveries	**(9)**	-
Colder than normal weather	**(33)**	(33)
Project development and transaction costs	**3**	-
Tax related adjustments	**(6)**	-
Out-of-period adjustment	**(71)**	-
Gains on sale of non-core assets and investment	**-**	(57)
Other	**(14)**	-
Adjusted earnings	**468**	492

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

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.

HIGHLIGHTS

	Three months ended March 31,	
	2015	2014
(unaudited; millions of Canadian dollars, except per share amounts)		
Earnings attributable to common shareholders		
Liquids Pipelines	**(422)**	44
Gas Distribution	**139**	136
Gas Pipelines, Processing and Energy Services	**16**	191
Sponsored Investments	**131**	84
Corporate	**(247)**	(111)
Earnings/(loss) attributable to common shareholders from continuing operations	**(383)**	344
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	46
	(383)	390
Earnings/(loss) per common share	**(0.46)**	0.48
Diluted earnings/(loss) per common share	**(0.46)**	0.47
Adjusted earnings[1]		
Liquids Pipelines	**192**	218
Gas Distribution	**106**	103
Gas Pipelines, Processing and Energy Services	**41**	59
Sponsored Investments	**127**	84
Corporate	**2**	28
	468	492
Adjusted earnings per common share	**0.56**	0.60
Cash flow data		
Cash provided by operating activities	**1,510**	333
Cash used in investing activities	**(1,866)**	(2,743)
Cash provided by financing activities	**225**	2,465
Dividends		
Common share dividends declared	**396**	291
Dividends paid per common share	**0.4650**	0.3500
Shares outstanding *(millions)*		
Weighted average common shares outstanding	**841**	820
Diluted weighted average common shares outstanding	**854**	830
Operating data		
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*		
Canadian Mainline[2]	**2,210**	1,904
Regional Oil Sands System[3]	**815**	671
Spearhead Pipeline	**150**	184
Gas Distribution - Enbridge Gas Distribution (EGD)		
Volumes *(billions of cubic feet)*	**217**	212
Number of active customers *(thousands)*[4]	**2,108**	2,076
Heating degree days[5]		
Actual	**2,232**	2,206
Forecast based on normal weather	**1,784**	1,777
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*		
Vector Pipeline	**1,855**	1,783
Enbridge Offshore Pipelines	**1,146**	1,371

1 Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by GAAP.

2 Canadian Mainline includes deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.

3 Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.

4 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.

5 Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD s franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.

FOR FURTHER INFORMATION PLEASE CONTACT:

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ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

March 31, 2015

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2015

This Management s Discussion and Analysis (MD&A) dated May 5, 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 months ended March 31, 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 March 31,	
	2015	2014
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**(422)**	44
Gas Distribution	**139**	136
Gas Pipelines, Processing and Energy Services	**16**	191
Sponsored Investments	**131**	84
Corporate	**(247)**	(111)
Earnings/(loss) attributable to common shareholders from continuing operations	**(383)**	344
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	46
Earnings/(loss) attributable to common shareholders	**(383)**	390
Earnings/(loss) per common share	**(0.46)**	0.48
Diluted earnings/(loss) per common share	**(0.46)**	0.47

Loss attributable to common shareholders was $383 million for the three months ended March 31, 2015, or a loss of $0.46 per common share, compared with earnings of $390 million, or $0.48 per common share, for the three months ended March 31, 2014. The Company delivered solid results from operations in the first quarter of 2015; however, the visibility and comparability of the 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 that over the long-term it supports the reliable cash flows and dividend growth upon which the Company s investor value proposition is based.

Other factors impacting the comparability of period-over-period earnings 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, as well as insurance recoveries of $9 million after-tax related to the Line 37 crude oil release, which occurred in June 2013.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge s 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 , estima forecast , plan , intend , target , believe and similar words suggesting future outcomes or statements regarding an ou 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 future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; the Canadian Restructuring Plan; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; 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; final approval of definitive transfer terms by Enbridge and Enbridge Income Fund Holdings Inc. (ENF) and Enbridge Income Fund (the Fund) with respect to the Canadian Restructuring Plan; receipt of all necessary shareholder and regulatory approvals that may be required for the Canadian Restructuring Plan; and weather. 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) or adjusted earnings/(loss) and associated per share amounts, the impact of the Canadian Restructuring Plan on Enbridge, the adjusted dividend payout policy 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 Canadian Restructuring Plan, revised dividend policy, adjusted earning guidance, 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 non-GAAP measures, including adjusted earnings/(loss), which represent 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. Management believes the presentation of non-GAAP measures such as adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company s dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. The table below summarizes the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Earnings/(loss) attributable to common shareholders	**(383)**	390
Adjusting items[1]:		
Changes in unrealized derivative fair value loss[2]	**977**	190
Make-up rights adjustments	**4**	2
Leak insurance recoveries	**(9)**	-
Colder than normal weather	**(33)**	(33)
Project development and transaction costs	**3**	-
Tax related adjustments	**(6)**	-
Out-of-period adjustment	**(71)**	-
Gains on sale of non-core assets and investment	**-**	(57)
Other	**(14)**	-
Adjusted earnings	**468**	492

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 March 31,	
	2015	2014
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**192**	218
Gas Distribution	**106**	103
Gas Pipelines, Processing and Energy Services	**41**	59
Sponsored Investments	**127**	84
Corporate	**2**	28
Adjusted earnings	**468**	492
Adjusted earnings per common share	**0.56**	0.60

3

Adjusted earnings were $468 million, or $0.56 per common share, for the three months ended March 31, 2015 compared with $492 million, or $0.60 per common share, for the three months ended March 31, 2014.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, adjusted earnings decreased quarter-over-quarter due to lower contributions from Canadian Mainline and Southern Lights Pipeline. Canadian Mainline adjusted earnings reflected the positive effects of higher throughput, higher terminalling revenues, a favourable United States/Canada foreign exchange rate and lower income taxes. However, these positive factors were more than offset by a lower quarter-over-quarter Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll, higher power costs associated with higher throughput and higher operating and administrative expense. Growing volumes on the system, together with the impact of a higher Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions as they come into service, including surcharges for the recently completed Edmonton to Hardisty Expansion, are expected to drive strong revenues and earnings growth over the balance of 2015. The majority of the economic benefit derived from Southern Lights Pipeline is now reflected in earnings from the Fund following the Fund s November 2014 subscription and purchase of Class A units of Enbridge subsidiaries, which provide the Fund a defined cash flow stream from Southern Lights Pipeline.

- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings decreased primarily due to the lower interim distribution rates applicable in the first quarter of 2015 compared with the interim rates applicable in the corresponding 2014 period. Any shortfall in revenues arising from the difference between interim and final 2015 rates will be adjusted during 2015 and will not have an impact on full year results, which are expected to be higher than the prior year. The decrease in EGD adjusted earnings was more than offset by 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, the decrease in adjusted earnings reflected the absence of earnings from Alliance Pipeline US, which was transferred to the Fund in November 2014, as well as lower earnings from Aux Sable due to lower fractionation margins. Partially offsetting the decrease in adjusted earnings was an increase in take-or-pay fees on the Company s investment in Cabin Gas Plant (Cabin).

- Within Sponsored Investments, adjusted earnings from Enbridge Energy Partners, L.P. (EEP) reflected higher throughput and tolls on EEP s major liquids pipelines, as well as contributions from new assets placed into service in 2014, the most prominent being the replacement and expansion of Line 6B. 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 also reflected distributions from Class D units which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued in January 2015 in connection with the transfer of Alberta Clipper.

- Also within Sponsored Investments, the Fund first quarter adjusted earnings reflected the impact of the transfer of natural gas and diluent pipeline interests from Enbridge, partially offset by higher financing costs associated with the debt issued to partially finance this transfer and higher income taxes. Adjusted earnings were also positively impacted by higher preferred unit distributions received by Enbridge from the Fund.

- Within the Corporate segment, an increase in Other Corporate loss reflected higher preference share dividends from an increase in the number of preference shares in 2014 to fund the Company s growth capital program.

RECENT DEVELOPMENTS

CANADIAN RESTRUCTURING PLAN

On March 31, 2015, Enbridge announced that it had delivered a formal proposal to a committee of independent members of the boards of Enbridge Commercial Trust (ECT) and ENF to transfer Enbridge s Canadian Liquids Pipelines business, comprised of Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., along with certain renewable energy assets, with a combined carrying value of approximately $17 billion and an associated secured growth capital program of approximately $15 billion, to the Fund (collectively, the Canadian Restructuring Plan). The formal proposal follows the Company s December 3, 2014 announcement of the proposed Canadian Restructuring Plan. The general terms and projected financial outcomes of the proposed transfer are substantially consistent with those originally described in that announcement and the MD&A for the year ended December 31, 2014.

Pursuant to the plan, ENF is expected to acquire an increasing interest in the transferred assets through investments in the equity of the Fund over a period of several years in amounts consistent with its equity funding capability. The Canadian Restructuring Plan was approved in principle by Enbridge s Board of Directors in December 2014, but remains subject to finalization of internal reorganization steps and a number of internal and external consents and approvals, including all necessary shareholder and regulatory approvals and final approval of definitive transfer terms by the Enbridge Board of Directors. The transfer also remains subject to approval by the boards of ECT and ENF, following a recommendation by a joint special committee. The joint special committee has been established and is comprised of independent directors of ENF and independent trustees of ECT and has engaged independent financial, technical and legal advisors to support its assessment of the proposed transfer. Assuming all necessary consents and approvals are obtained, the transfer and initial investment by ENF are targeted for completion by mid-2015. However, there can be no assurance that the planned restructuring will be completed in the manner contemplated, or at all, or that the current market conditions and Enbridge s future forecast, based on such market conditions, will not materially change.

Enbridge is also in the process of reviewing a potential United States restructuring plan which would involve the transfer of its United States liquids pipelines assets to EEP. This review has not yet progressed to a conclusion.

DIVIDENDS

In December 2014, the Company announced an increase in its targeted dividend payout range from 60% to 70% of adjusted earnings to 75% to 85% of adjusted earnings. Following that announcement, the Company increased its quarterly common share dividend by approximately 33% to $0.465 per share effective March 1, 2015.

LIQUIDS PIPELINES

Seaway Pipeline Regulatory Matter

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. Initially, the Federal Energy Regulatory Commission (FERC) rejected the application in March 2012 and Seaway Pipeline appealed to the District of Columbia Circuit. In response, the FERC set the application for further proceedings and the appeal was stayed. Since the FERC had not issued a ruling on this 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. During the evidentiary stage, FERC staff filed evidence stating that the committed and uncommitted rates are subject to review and adjustment. Seaway Pipeline filed a Petition for Declaratory Order (PDO) requesting the FERC confirm that it will honour and uphold existing contracts. The FERC issued a decision denying the PDO on procedural grounds but stated that it will uphold its longstanding policy of honouring contracts.

The FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (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.

In relation to the original market-based rate application, the 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 to the application alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. No procedural schedule has been set as of this date.

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, if any, which might result from discussions with the EPA.

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. On February 12, 2015, the EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modifications and acknowledged that EEP had completed the dredging requirements of the Order. At this time, EEP has completed all of the SORA.

Regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who 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.

As at March 31, 2015, EEP s total 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 March 31, 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

A release of crude oil from Line 6A of EEP s Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. One 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 Recoveries

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 up for renewal 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 March 31, 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 March 31, 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. While EEP believes that those costs are eligible for recovery, there can be no assurance that EEP will prevail in the arbitration.

Enbridge has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2015 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 six 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, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material to the Company s results of operations or financial condition.

As at March 31, 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. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

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.	Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.7 billion	2013-2015 (in phases)	Substantially Complete
2.	Canadian Mainline Expansion	$0.7 billion	$0.5 billion	2015	Under construction
3.	Surmont Phase 2 Expansion	$0.3 billion	$0.3 billion	2014-2015 (in phases)	Complete
4.	Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.5 billion	2013-2015 (in phases)	Under construction
5.	Sunday Creek Terminal Expansion	$0.2 billion	$0.2 billion	2015	Under construction
6.	Woodland Pipeline Extension	$0.7 billion	$0.6 billion	2015	Under construction
7.	Edmonton to Hardisty Expansion	$1.8 billion	$1.2 billion	2015 (in phases)	Under construction
8.	Southern Access Extension	US$0.6 billion	US$0.2 billion	2015	Under construction
9.	AOC Hangingstone Lateral	$0.2 billion	$0.1 billion	2015	Under construction
10.	JACOS Hangingstone Project	$0.2 billion	No significant expenditures to date	2016	Pre-construction
11.	Regional Oil Sands Optimization Project	$2.6 billion	$1.3 billion	2017	Under construction
12.	Norlite Pipeline System3	$1.3 billion	No significant expenditures to date	2017	Pre-construction
13.	Canadian Line 3 Replacement Program	$4.9 billion	$0.5 billion	2017	Pre-construction

GAS DISTRIBUTION					
14.	Greater Toronto Area Project	$0.8 billion	$0.3 billion	2015	Under construction

GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
15.	Keechi Wind Project	US$0.2 billion	US$0.2 billion	2015	Complete
16.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-2015 (in phases)	Under construction
17.	Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	2015	Under construction
18.	Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
19.	Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Under construction
20.	Stampede Oil Pipeline	US$0.2 billion	No significant expenditures to date	2018	Pre-construction
SPONSORED INVESTMENTS					
21.	EEP - Eastern Access4	US$2.7 billion	US$2.2 billion	2013-2016 (in phases)	Under construction
22.	EEP - Lakehead System Mainline Expansion4	US$2.3 billion	US$1.3 billion	2014-2017 (in phases)	Under construction
23.	EEP - Beckville Cryogenic Processing Facility	US$0.2 billion	US$0.1 billion	2015	Under construction
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$0.6 billion	2017	Pre-construction
26.	EEP - U.S. Line 3 Replacement Program	US$2.6 billion	US$0.2 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 March 31, 2015.

3 Enbridge 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 Enbridge will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.

LIQUIDS PIPELINES

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 Enbridge 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*.

Enbridge is undertaking a reversal of its 240,000 barrels per day (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 National Energy Board (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, Enbridge 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, which is a prerequisite to allowing the operation of the project.

Subject to NEB approval of the Leave to Open application, Enbridge expects to place the Line 9B Reversal and Line 9 Capacity Expansion Project into service in the second quarter of 2015. In its February approval, the NEB also imposed additional obligations on Enbridge that direct the Company to take a life-cycle approach to water crossings and valves, requiring the Company to perform ongoing analysis to ensure optimal protection of the area s water resources.

The conditions previously imposed by the NEB, including costs associated with additional NEB mandated integrity testing, increased the total expected cost of the projects to $0.7 billion, inclusive of costs related to the previously mentioned Line 9A reversal. Enbridge has reached an agreement with shippers to recover a portion of the incremental cost of additional valves ordered by the NEB through a toll surcharge. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.7 billion.

On July 31, 2014, Enbridge 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, Enbridge requested that the NEB approve the tolls on an interim basis to allow for time to engage shippers in further discussions to attempt to resolve the outstanding issues. The NEB established interim tolls, which remain in effect, and in late 2014, Enbridge and shippers filed letters with the NEB requesting that it establish a process to consider the issues. The NEB has set a written hearing with oral reply argument to be heard on May 28, 2015.

Canadian Mainline Expansion

Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases that involve 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 is expected to be completed in the third quarter of 2015 at an expected cost of approximately $0.5 billion. The estimated cost of the entire expansion is approximately $0.7 billion, with expenditures to date of approximately $0.5 billion. Receipt of the applicable regulatory approvals 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 any delays in obtaining applicable regulatory approvals. 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 is undertaking 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 are comprised of upgrading existing booster pumps, installing additional booster pumps and adding new tank line connections. These projects have varying completion dates from 2013 through the second quarter of 2015. The cost of the project is expected to be approximately $0.7 billion, with expenditures to date of approximately $0.5 billion.

Sunday Creek Terminal Expansion

In 2014, the Company announced it will construct 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 includes 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 estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.2 billion and a targeted in-service date in the third quarter of 2015.

Woodland Pipeline Extension

The joint venture Woodland Pipeline Extension Project will extend the Woodland Pipeline south from Enbridge s Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 388-kilometre (241-mile), 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. Enbridge s share of the estimated capital cost of the project is now approximately $0.7 billion, with expenditures incurred to date of approximately $0.6 billion. The project has a target in-service date of the third quarter of 2015.

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 Enbridge 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 third quarter of 2015. The total cost of the project is expected to be approximately $1.8 billion, with expenditures to date of approximately $1.2 billion.

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 bpd, as well as additional tankage and two new pump stations. Subject to regulatory and other approvals, the project is expected to be placed into service in the fourth quarter of 2015. Enbridge s share of the estimated capital cost is expected to be approximately US$0.6 billion, with expenditures to date of approximately US$0.2 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 Enbridge s existing Cheecham Terminal and related facility modifications at Cheecham, Alberta. Phase I 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

Enbridge 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. Enbridge plans to construct a new 53-kilometre (33-mile), 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge s existing Cheecham Terminal. The project, which will provide capacity of 40,000 bpd and is expected to enter service in 2016, is estimated to cost approximately $0.2 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 Enbridge 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 would 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 $1.3 billion.

Subject to regulatory and other approvals, 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. Along with the Norlite Pipeline System (Norlite), discussed below, the Wood Buffalo Extension and the Athabasca Pipeline Twin will be the conduit to ship diluent to, and blended bitumen from, the Fort Hills Project which has an expected 2017 in-service date.

Norlite Pipeline System

Enbridge 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 both 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 Enbridge s Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership s East Tank Farm, which is adjacent to Enbridge 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 as well as finalization of scope, Norlite is now expected to be completed in 2017 at an estimated cost of approximately $1.3 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 portion of the Line 3 Replacement Program (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. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system s overall western Canada export capacity.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in late 2017. Following the completion of a definitive cost estimate in the second quarter of 2014, the estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.5 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*.

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 and a 23-kilometre (14-mile), 36-inch diameter pipeline in Toronto, Ontario, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. Construction began in January 2015 and completion of the project is expected in the fourth quarter of 2015 at an estimated cost of approximately $0.8 billion, with expenditures to date of approximately $0.3 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, Enbridge is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the 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 and the Big Foot Oil Pipeline (Big Foot Pipeline) portion is expected to be placed into service in the third 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., Enbridge is constructing a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge s undertaking of the WRGGS construction discussed above. Upon completion of the project, Enbridge will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.2 billion. As noted above, the Big Foot Pipeline is expected to enter service in the third quarter of 2015.

Aux Sable Extraction Plant Expansion

In 2014, the Company approved the expansion of fractionation capacity and related facilities at its 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 2016, with Enbridge 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 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 (3,500 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 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 completed projects was approximately US$2.4 billion. For discussion on Enbridge s portion of Eastern Access, refer to *Growth Projects Commercially Secured Projects Liquids Pipelines 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 expected to cost approximately US$0.3 billion, with an expected in-service date of early 2016.

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$2.2 billion. The Eastern

Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

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 included increasing capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase of the expansion will increase 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 is expected to be completed in the third quarter of 2015. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower with no pipeline construction and are subject to regulatory and other 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 the Federal regulatory approval for the expansion to 800,000 bpd 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 applicable regulatory approvals.

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 Enbridge 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 Enbridge s application to the DOS to increase Alberta Clipper s permitted cross border capacity is still pending. Enbridge has moved to intervene in the case and a decision at the trial level is not expected before the fourth quarter of 2015.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. Both phases of the Southern Access expansion 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 also plans to undertake a further expansion of the Southern Access line between Superior, Wisconsin and Flanagan, Illinois to increase capacity from 560,000 bpd to 1,200,000 bpd and add crude oil tankage at new and existing sites. The pipeline expansion will be split into two tranches. The first tranche will expand the pipeline capacity to 800,000 bpd at an estimated capital cost of approximately US$0.4 billion and is expected to be in service in the second quarter of 2015. 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 second quarter of 2016. The second tranche, which remains subject to regulatory and other approvals, will expand the pipeline capacity to 1,200,000 bpd at an estimated capital cost of approximately US$0.4 billion and is expected to be in service in 2017. The Company, in conjunction with shippers, decided to delay the in-service date of the final tranche of the Line 61 expansion to align more closely with the currently anticipated in-service date for the Sandpiper Project (Sandpiper), which will drive the need for additional downstream capacity on the Lakehead System.

On April 17, 2015, EEP filed an amended tariff with the FERC to provide shippers with optional in-transit merchant storage service. The in-transit merchant storage service will provide shippers the ability to off-load barrels in-transit at Flanagan, Illinois or Superior, Wisconsin, direct them into temporary storage and later return them to the Lakehead System for delivery to their ultimate destinations. This service will be included in the applicable tariff rate from the initial origin point to the ultimate delivery point.

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. Subject to regulatory and other approvals, the new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in the third 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$1.3 billion. EEP will

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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%.

Beckville Cryogenic Processing Facility

EEP and its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP), are constructing a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant will offer 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 planned natural gas processing capability of 150 mmcf/d and is also expected to produce 8,500 bpd of NGL. The Beckville Plant is now expected to be placed into service in the second quarter of 2015 at an estimated cost of approximately US$0.2 billion. Expenditures incurred to date are approximately US$0.1 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 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 are projected to be placed into service by late 2015, with the lateral expected to be in service by mid-2016. 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$0.6 billion.

EEP is in the process of obtaining the appropriate construction permits within the state of Minnesota for Sandpiper. The permits require both a Certificate of Need and an approval of the pipeline s route (Route Permit) from the Minnesota Public Utilities Commission (MNPUC). In April 2015, the ALJ recommended that the MNPUC grant approval of the Certificate of Need based on evidence provided by Enbridge that the need for the system has been demonstrated. The ALJ also recommended that no alternative routes to that proposed by Enbridge should be considered in subsequent Route Permit process. The MNPUC is expected to take the ALJ s recommendation into account and make a decision on the Certificate of Need in the third quarter of 2015. A separate MNPUC review of the proposed pipeline route will follow. Subject to regulatory and other approvals, particularly in the State of Minnesota, the expected in-service date for Sandpiper is 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. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system s overall western Canada export capacity.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in late 2017 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.2 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 Enbridge 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. 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 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 Federal Court then set a schedule which would culminate with the filing of the Appellants Memoranda of Fact and Law by May 22, 2015 and the Respondents Memoranda by June 23, 2015. Based on this schedule, Northern Gateway expects that the hearing on the Application will occur in the fall of 2015. Depending on the outcome of these proceedings, which is anticipated late 2015, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

The Company has reviewed an updated cost estimate of Northern Gateway based on a 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, 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.

Subject to continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company estimates that Northern Gateway could be in service in 2019 at the earliest. The timing and outcome of judicial reviews could also impact the start of construction or other project activities, which may lead to a delay in the start of operations beyond the current forecast.

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 Joint Review Panel (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 http://www.gatewayfacts.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 March 31,	
	2015	2014
(millions of Canadian dollars)		
Canadian Mainline	**125**	141
Regional Oil Sands System	**48**	42
Seaway and Flanagan South Pipelines	**10**	10
Spearhead Pipeline	**6**	9
Southern Lights Pipeline	**2**	12

Feeder Pipelines and Other	**1**	4
Adjusted earnings	**192**	218
Canadian Mainline - changes in unrealized derivative fair value loss	**(616)**	(172)
Canadian Mainline - Line 9B costs incurred during reversal	**(2)**	-
Regional Oil Sands System - leak insurance recoveries	**9**	-
Regional Oil Sands System - make-up rights adjustment	**4**	(2)
Seaway and Flanagan South Pipelines - make-up rights adjustment	**(5)**	-
Spearhead Pipeline - make-up rights adjustment	**(1)**	-
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	-
Feeder Pipelines and Other - project development costs	**(2)**	-
Earnings/(loss) attributable to common shareholders	**(422)**	44

Liquids Pipelines earnings/(loss) were impacted by the following adjusting items:

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

- Canadian Mainline loss for the first quarter of 2015 included depreciation and interest expenses charged to Line 9B while it is idled and undergoing a reversal as part of the Company s Eastern Access initiative.

- Regional Oil Sands System earnings for the first quarter of 2015 included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013.

- Feeder Pipelines and Other loss for the first quarter of 2015 included certain business development costs related to Northern Gateway that are anticipated to be recovered over the life of the project.

Canadian Mainline

Canadian Mainline adjusted earnings decreased in the first quarter of 2015 compared with the corresponding 2014 first quarter. Positively impacting adjusted earnings was higher throughput from strong oil sands production combined with strong refinery demand in the midwest market partly due to a start-up of a midwest refinery s conversion to heavy oil processing in the second quarter of 2014. Higher throughput was also achieved from continued efforts by the Company to optimize capacity utilization and to enhance scheduling efficiency with shippers. Other factors contributing to an increase in adjusted earnings included higher terminalling revenues and the impact of a stronger United States dollar compared with the Canadian dollar as the IJT Benchmark Toll and its components are set in United States dollars. Also positively impacting adjusted earnings were lower income tax expense, which reflected current income taxes only and were lower due to higher available tax deductions from a larger asset base and lower earnings on a period-over-period basis.

More than offsetting the positive factors noted above was a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher due to the recovery of incremental costs associated with EEP s growth projects. Effective April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased from US$1.53 per barrel to US$1.63 per barrel, following EEP s April 1, 2015 tariff filing for its Lakehead System. Growing volumes on the system, together with the impact of a higher Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions as they come into service, including surcharges for the recently completed Edmonton to Hardisty Expansion, are expected to drive strong revenues and earnings growth over the balance of 2015. Other factors which contributed to lower adjusted earnings included higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities.

In the first quarter of 2015, the Company also commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $9 million in revenues was recorded in the first quarter, but the amount was offset by a corresponding increase in operating and administrative expense. For further details, refer to *Critical Accounting Estimates*.

Supplemental information on Canadian Mainline adjusted earnings for the three months ended March 31, 2015 and 2014 is as follows:

	Three months ended March 31,	
(millions of Canadian dollars)		
Revenues	**381**	373
Expenses		
Operating and administrative	**108**	83
Power	**50**	38
Depreciation and amortization	**67**	66
	225	187
	156	186
Other income	**4**	1
Interest expense	**(45)**	(40)
	115	147
Income taxes recovery/(expense)	**10**	(6)
Adjusted earnings	**125**	141
Effective United States to Canadian dollar exchange rate[1]	**1.08**	1.02

(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$4.02**	$3.98
Lakehead System Local Toll[3]	**$2.49**	$2.17
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.53**	$1.81

1 Inclusive of realized gains and losses on foreign exchange derivative financial instruments.

2 The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2014, the IJT Benchmark Toll increased from US$3.98 to US$4.02.

3 The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. In 2014, EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the Canadian Association of Petroleum Producers concerning certain components of the tariff rate structure. The toll application was filed with the FERC on June 27, 2014, and effective August 1, 2014, the Lakehead System Toll increased from US$2.17 to US$2.49. Effective April 1, 2015, this toll decreased to US$2.39.

4 The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll and the Lakehead System Local Toll. Effective July 1, 2014, this toll increased from US$1.81 to US$1.85 and subsequently decreased to US$1.53 effective August 1, 2014, coinciding with the revised Lakehead System Local Toll. Effective April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased to US$1.63.

Throughput volume[1] *(thousand barrels per day (kbpd))*	**2,210**	1,904

1 Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and Eastern Canada deliveries entering the mainline in Western Canada.

Regional Oil Sands System

Regional Oil Sands System adjusted earnings increased for the three months ended March 31, 2015 compared with the first quarter of 2014. Adjusted earnings growth was driven by incremental earnings from the Norealis Pipeline which was completed in April 2014 and higher uncommitted volumes and capital expansion fee revenues on the Waupisoo Pipeline. Partially offsetting the positive adjusted earnings increase was a reduction in contracted volumes on the Athabasca Mainline, although it was mitigated in part by higher uncommitted volumes on this pipeline.

Seaway and Flanagan South Pipelines

Seaway and Flanagan South Pipelines adjusted earnings for the three months ended March 31, 2015 were comparable with the first quarter of 2014. During the first quarter of 2015, as a result of Canadian Mainline apportionment, throughput on Seaway and Flanagan South Pipelines was lower than the throughput committed on these pipelines. When committed shippers on Flanagan South are unable to fulfill their volume commitments due to apportionment, they are provided with temporary relief to make up those volumes during the course of their contracts or the apportioned volumes are added on to the end of the contract term. The impact of upstream apportionment is expected to be alleviated as the Company expands its mainline system in 2015 and through continued system optimization measures.

Spearhead Pipeline

Spearhead Pipeline adjusted earnings decreased in the first quarter of 2015 compared with the first quarter of 2014. Lower throughput due to upstream apportionment drove lower adjusted earnings, partially offset by a decrease in power cost associated with the lower throughput.

Southern Lights Pipeline

Southern Lights Pipeline earnings for the first quarter of 2015 decreased compared with the corresponding 2014 three-month period. The majority of the economic benefit derived from Southern Lights Pipeline is now reflected in earnings from the Fund following the Fund s November 2014 subscription and purchase of Class A units of Enbridge subsidiaries, which provide a defined cash flow stream from Southern Lights Pipeline.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted earnings for the three months ended March 31, 2015 decreased compared with the corresponding 2014 period. Higher business development costs not eligible for capitalization and lower average tolls on Olympic Pipeline were partially offset by higher earnings from Eddystone Rail Project completed in April 2014.

GAS DISTRIBUTION

(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**85**	91
Other Gas Distribution and Storage	**21**	12
Adjusted earnings	**106**	103
EGD - colder than normal weather	**33**	33
Earnings attributable to common shareholders	**139**	136

EGD adjusted earnings decreased for the three months ended March 31, 2015 compared with the corresponding 2014 three-month period. The decrease in adjusted earnings was largely attributable to the timing of the approval of EGD s distribution rates by the Ontario Energy Board (OEB). In both the first quarters of 2015 and 2014, EGD operated under interim distribution rates. In the first quarter of 2015, the interim distribution rates were lower than the interim rates applicable in the comparative first quarter of 2014, partially offset by lower depreciation expense embedded within these distribution rates. The lower depreciation expense relates to applying the new approach for determining depreciation and future removal and site restoration reserves under the customized incentive rate plan approved by the OEB in the second half of 2014.

In April 2015, the OEB approved a comprehensive settlement proposal, inclusive of 2015 rates. The approved settlement allows for final 2015 rates to be implemented with the July 2015 Quarterly Rate Adjustment Mechanism, and will be effective January 1, 2015. EGD filed a draft rate order in April 2015 and anticipates approval by the OEB by the end of May 2015. EGD expects to collect and record the difference between the interim rates and applicable 2015 rates during 2015. The Company s policy is to account for regulatory decisions in the period in which they are received and will record the impact of the approved settlement prospectively. EGD s full year results are expected to be higher than the prior year.

Other Gas Distribution and Storage earnings for the first quarter of 2015 increased compared with the corresponding first quarter of 2014. The increase in earnings reflected the absence of a loss that 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. Excluding the impact of the above noted contract which expired in October 2014, EGNB 2015 first quarter earnings increased slightly due to higher distribution revenues.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

[redacted]

(millions of Canadian dollars)		
Aux Sable	**3**	7
Energy Services	**20**	24
Alliance Pipeline US	**-**	12
Vector Pipeline	**5**	6
Canadian Midstream	**10**	5
Enbridge Offshore Pipelines (Offshore)	**(1)**	4
Other	**4**	1
Adjusted earnings	**41**	59
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(26)**	136
Offshore - gain on sale of non-core assets	**-**	43
Other - changes in unrealized derivative fair value gains/(loss)	**1**	(1)
Earnings attributable to common shareholders	**16**	237

Gas Pipelines, Processing and Energy Services earnings were impacted by the following adjusting items:

- Energy Services earnings/(loss) for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.

- Enbridge Offshore Pipelines (Offshore) earnings for the first quarter of 2014 included a gain from the disposal of non-core assets.

- Other earnings for each period reflected changes in unrealized fair value gains and losses on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from the Blackspring Ridge Wind Project (Blackspring Ridge).

Aux Sable earnings decreased, as anticipated, for the three months ended March 31, 2015 compared with the 2014 comparative period and reflected lower fractionation margins resulting from a weaker commodity price environment and the loss of a producer processing contract at the Palermo Conditioning Plant.

Energy Services operates a physical commodity marketing business which captures value from quality, time and location differentials when opportunities arise. To execute these strategies Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Energy Services adjusted earnings for the first quarter of 2015 decreased compared with the corresponding 2014 three month period. The decrease in adjusted earnings was attributable to narrowing location differentials and less favourable conditions in certain markets, particularly those accessed by committed transportation capacity, combined with associated unrecovered demand charges. Higher adjusted earnings in first quarter of 2014 also reflected the impact of more favourable natural gas differentials caused by abnormal winter weather conditions. Partially offsetting these negative effects was the absence of losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second quarter of 2014, the Company closed out a forward component of these derivative contracts which had been determined to be no longer effective. Also partially offsetting the decrease in adjusted earnings were more favourable conditions in certain markets that enable Energy Services to capture more profitable tank management arbitrage opportunities.

The absence of Alliance Pipeline US earnings in the first quarter of 2015 reflected the transfer of Alliance Pipeline US to the Fund in November 2014.

Vector Pipeline earnings were comparable between the first quarters of 2015 and 2014 and reflected the impact of increased demand for natural gas due to abnormal winter weather conditions.

Canadian Midstream earnings increased in the three months ended March 31, 2015 compared with the comparative 2014 period. Higher earnings reflected an increase in take-or-pay fees on the Company s investment in Cabin and the Pipestone and Sexsmith Sour Gas Gathering and Compression Facilities, as well as higher volumes at Pipestone.

Offshore adjusted earnings decreased in the first quarter of 2015 compared with the first quarter of 2014. The decrease in adjusted earnings reflected the absence of earnings from the disposals of non-core assets finalized in March 2014.

Adjusted earnings from Other for the first quarter of 2015 increased compared with the equivalent 2014 period and reflected contributions from new wind farms including Blackspring Ridge completed in May 2014 and the Magic Valley and Wildcat wind farms acquired at the end of 2014.

SPONSORED INVESTMENTS

[redacted]

(millions of Canadian dollars)		
Enbridge Energy Partners, L.P. (EEP)	**62**	45
Enbridge Energy, Limited Partnership (EELP)	**20**	7
Enbridge Income Fund (the Fund)	**45**	32
Adjusted earnings	**127**	84
The Fund - make up rights adjustment	**(1)**	-
The Fund - changes in unrealized derivative fair value loss	**(11)**	-
The Fund - unrealized intercompany foreign exchange gains	**16**	-
Earnings attributable to common shareholders	**131**	84

EEP adjusted earnings increased in the first quarter of 2015 compared with the corresponding 2014 period. Adjusted earnings reflected similar trends experienced in the latter half of 2014 whereby earnings growth was driven by higher throughput and tolls in EEP s liquids business, as well as contributions from new assets placed into service in 2014, the most prominent being the replacement and expansion of Line 6B. In addition, EEP adjusted earnings reflected incremental earnings from the transfer on

January 2, 2015 of the remaining 66.7% interest in Alberta Clipper previously held by Enbridge through Enbridge Energy, Limited Partnership (EELP). Partially offsetting the increase in adjusted earnings in EEP s liquids business were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base. Also contributing to higher earnings in the first quarter of 2015 were distributions from Class D units which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued in January 2015 in connection with the transfer of Alberta Clipper. Finally, the first quarter of 2015 reflected lower volumes within EEP s natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary, MEP.

EELP earnings reflect Enbridge s interests in both the Eastern Access and Lakehead System Mainline expansion projects. Earnings from EELP increased due to contributions from assets recently placed into service, most notably the expansion of Line 6B completed in phases during 2014 as part of the

Company s Eastern Access Program. Partially offsetting the increase in earnings was the absence of earnings from EELP s interest in Alberta Clipper which was transferred to EEP on January 2, 2015.

Adjusted earnings from the Fund increased for the three months ended March 31, 2015 compared with the corresponding 2014 first quarter. The increase in adjusted earnings reflected incremental earnings from natural gas and diluent pipeline interests transferred by Enbridge to the Fund in November 2014. Partially offsetting the increase in earnings were higher financing costs associated with debt raised to acquire the natural gas and diluent pipeline interests and higher income taxes. Finally, adjusted earnings were also positively impacted by higher preferred unit distributions received from the Fund.

CORPORATE

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Noverco Inc. (Noverco)	**30**	29
Other Corporate	**(28)**	(1)
Adjusted earnings	**2**	28
Noverco - changes in unrealized derivative fair value loss	**(3)**	(4)