Enbridge Inc.

ENB

Third Quarter
Interim Report to Shareholders
For the nine months ended September 30, 2014

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

September 30, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2014

This Management's Discussion and Analysis (MD&A) dated November 4, 2014 should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and nine months ended September 30, 2014, 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, 2013. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**(31)**	301	**444**	381
Gas Distribution	**(11)**	(85)	**144**	49
Gas Pipelines, Processing and Energy Services	**88**	68	**386**	257
Sponsored Investments	**108**	75	**279**	189
Corporate	**(234)**	62	**(233)**	(163)
Earnings/(loss) attributable to common shareholders from continuing operations	**(80)**	421	**1,020**	713
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**46**	-
Earnings/(loss) attributable to common shareholders	**(80)**	421	**1,066**	713
Earnings/(loss) per common share	**(0.10)**	0.52	**1.29**	0.89
Diluted earnings/(loss) per common share	**(0.10)**	0.51	**1.27**	0.88

Loss attributable to common shareholders was $80 million for the three months ended September 30, 2014, or a $0.10 loss per common share, compared with earnings attributable to common shareholders of $421 million or $0.52 per common share, for the three months ended September 30, 2013. The Company continued to deliver strong quarter-over-quarter earnings growth, as discussed in *Adjusted Earnings*; however, the Company's quarterly results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth.

The comparability of the Company's quarter-over-quarter earnings was also impacted by certain out-of-period adjustments recognized in the third quarter of 2013, including a non-cash adjustment of $37 million after-tax to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts within Regional Oil Sands System. Also in Regional Oil Sands System, there was an out-of-period adjustment of $31 million after-tax related to the recovery of income taxes under a long-term contract, partially offset by a related correction to deferred income tax expense. In addition, in the third quarter of 2013, in the Gas Distribution segment an out-of-year adjustment of $56 million after-tax was recognized reflecting an increase to gas transportation costs which had incorrectly been deferred. Finally, the Company's earnings for the three months ended September 30, 2014 reflected an accrual of US$51 million ($12 million after-tax attributable to Enbridge) recognized by Enbridge Energy Partners, L.P. (EEP) in respect of the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*

Earnings attributable to common shareholders were $1,066 million for the nine months ended September 30, 2014, or $1.29 per common share, compared with $713 million, or $0.89 per common share, for the nine months ended September 30, 2013. The Company has delivered strong earnings growth in the first nine months of 2014; however, the magnitude of this growth and the comparability of the Company's results are impacted by changes in unrealized derivative fair value gains and losses, as well as the out-of-period adjustments noted above. In addition, earnings for the nine months ended September 30, 2014 also reflected a $43 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. Finally, the Company's earnings, for both 2014 and 2013, reflected certain costs and related insurance recoveries related to the Line 6B crude oil release, see *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release,* as well as 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 and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' 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: 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; 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 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 and interest rates; the 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; 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, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates and expected capital expenditures, include: 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; and the impact of weather and customer and regulatory approvals on construction and in-service schedules.

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

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), 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 or loss are presented net of amounts realized on the settlement of derivative contracts during the applicable period. Management believes the presentation of 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. See Non-GAAP Reconciliations *for a reconciliation of the GAAP and non-GAAP measures.*

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**221**	187	**659**	565
Gas Distribution	**(9)**	(29)	**109**	109
Gas Pipelines, Processing and Energy Services	**20**	54	**106**	186
Sponsored Investments	**126**	86	**306**	224
Corporate	**(13)**	(20)	**(15)**	(12)
Adjusted earnings	**345**	278	**1,165**	1,072
Adjusted earnings per common share	**0.41**	0.34	**1.41**	1.33

Adjusted earnings were $345 million, or $0.41 per common share, for the three months ended September 30, 2014 compared with $278 million, or $0.34 per common share, for the three months ended September 30, 2013. Adjusted earnings were $1,165 million, or $1.41 per common share, for the nine months ended September 30, 2014 compared with $1,072 million, or $1.33 per common share, for the nine months ended September 30, 2013.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, higher throughput on Canadian Mainline drove an increase in adjusted earnings for the three and nine months ended September 30, 2014. The increase in throughput was attributable to several factors including: increased oil sands production; 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; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Canadian Mainline earnings for the three and nine months ended September 30, 2014 reflected a lower average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll compared with the corresponding 2013 periods. Finally, Canadian Mainline adjusted earnings continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013 while it is being reversed and expanded as part of the Company's Eastern Access initiative.
- Also within Liquids Pipelines, Regional Oil Sands System adjusted earnings increased due to contributions from the Norealis Pipeline, which was completed in April 2014, and higher throughput

on the Athabasca mainline which were partially offset by higher operating and administrative, depreciation, interest and tax expenses.

- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings increased slightly and reflected the August 22, 2014 Ontario Energy Board (OEB) rate order (the Rate Order) under the incentive rate (IR) mechanism which approved the final rates with an effective date of January 1, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. The Rate Order resulted in a lower depreciation expense under a new approach for determining depreciation and future removal and site restoration reserves. This positive effect was partially offset by reduced final rates requiring a refund of a portion of the previously collected interim rates to customers.
- Within Gas Pipelines, Processing and Energy Services, the decrease in adjusted earnings reflected weaker Energy Services results compared with a very strong 2013. Narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with unrecovered demand charges, resulted in lower adjusted earnings for the first nine months of 2014. In addition to the trends noted above, adjusted earnings for the nine-month period of 2014 decreased as a result 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. Partially offsetting the decrease in adjusted earnings were favourable natural gas location differentials caused by abnormal winter weather conditions in the first quarter of 2014.
- Within Sponsored Investments, EEP adjusted earnings reflected increased contributions from EEP's liquids business due to new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on EEP's major liquids pipelines. New assets placed into service include the replacement and expansion of Line 6B as part of Enbridge and EEP's Eastern Access initiative. Enbridge also benefitted from the completion of Line 6B replacement and expansion through its 75% interest in the United States portion of the Eastern Access expansion projects held through Enbridge Energy, Limited Partnership (EELP). Within EEP's natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP), lower volumes had a negative impact on adjusted earnings.
- Also within Sponsored Investments, Enbridge Income Fund (the Fund) adjusted earnings reflected strong performance from the Fund's liquids business. Also contributing to period-over-period growth in adjusted earnings for the first nine months of 2014 was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013. Partially offsetting the adjusted earnings increase were higher income taxes, which also drove lower 2014 third quarter earnings.
- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings for the nine months ended September 30, 2014 decreased compared with the corresponding 2013 period. Excluding the impact of a small one-time gain on sale of an investment in the first quarter of 2013 and an equity earnings true-up adjustment recognized in the first quarter of 2013, Noverco adjusted earnings were comparable between periods.
- Also within the Corporate segment, Other Corporate adjusted loss decreased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. The decreased loss reflected lower net corporate segment finance costs and lower income taxes partially offset by higher preference share dividends due to an increase in the number of preference shares outstanding.

RECENT DEVELOPMENTS

CHIEF FINANCIAL OFFICER SUCCESSION PLANS

On October 10, 2014, the Company announced the appointment of John Whelen to Executive Vice President and Chief Financial Officer, effective October 15, 2014. J. Richard Bird will remain Executive Vice President, Corporate Development until his retirement on December 31, 2014. The Company had previously announced on June 18, 2014, Mr. Bird's planned retirement and the split of his responsibilities into two separate roles of Chief Financial Officer and Chief Development Officer. Vern Yu was appointed Senior Vice President, Corporate Development effective July 1, 2014 and will continue to report to Mr. Bird.

LIQUIDS PIPELINES

Seaway Pipeline

Seaway Crude Oil Pipeline (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. Seaway Pipeline is currently evaluating whether it will file a new market based rate application under the new methodology.

GAS DISTRIBUTION

Enbridge Gas Distribution – Incentive Regulation

On July 17, 2014, the OEB approved EGD's five-year customized IR application, with modifications. The customized IR application establishes the methodology for determining rates for the distribution of natural gas over a five-year period from 2014 through 2018 and will allow EGD to recover its expected capital investment amounts, as well as an opportunity to earn above the allowed return on equity. The OEB decision also allowed for final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism with an effective date of January 1, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB Rate Order under the IR mechanism approved the final rates with an effective date of January 1, 2014.

The Rate Order approved a new approach for determining depreciation and future removal and site restoration reserves resulting in a lower depreciation expense. The Rate Order also approved reduced final rates requiring a refund of a portion of the previously collected interim rates to customers.

Enbridge Gas New Brunswick – Regulatory Matter

In 2012, the Government of New Brunswick enacted final rates and tariff regulation that affected the franchise agreement between Enbridge Gas New Brunswick Inc. (EGNB) and the province of New Brunswick, including the ability for EGNB to recover a deferred regulatory asset.

Also in 2012, EGNB commenced legal proceedings against the Government of New Brunswick seeking damages for breach of contract and commenced a separate application to quash the Government of New Brunswick's rate and tariffs regulation. EGNB's appeal in the latter proceeding was ultimately successful in part, as the Court of Appeal ruled that the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor in Council. The Court of Appeal upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. EGNB's 2014 rate application was approved in April 2014 by New Brunswick Energy and Utilities Board (EUB). EGNB has filed its application for 2015 rates with the EUB and the rate case is ongoing.

On February 4, 2014, EGNB commenced a further legal proceeding against the Government of New Brunswick. The action seeks damages for improper extinguishment of the deferred regulatory asset that was previously eliminated from EGNB's Consolidated Statements of Financial Position.

There is no assurance that any of EGNB's legal proceedings against the Province of New Brunswick will be successful or will result in any recovery.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Lac Alfred and Massif du Sud Wind Projects

In September 2014, the Company entered into an agreement to purchase additional interests in the 300-Megawatt (MW) Lac Alfred Wind Project (Lac Alfred) and the 150-MW Massif du Sud Wind Project (Massif du Sud) from existing partner, EDF EN Canada Inc. Under the agreement, Enbridge will invest approximately $225 million to acquire an additional 17.5% interest in Lac Alfred and an additional 30% interest in Massif du Sud. The Lac Alfred transaction closed in October 2014 and Enbridge now holds a 67.5% interest in Lac Alfred. The Massif du Sud transaction is expected to close in the fourth quarter of 2014 and Enbridge will hold an 80% interest in Massif du Sud upon closing of the transaction.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Sponsored Vehicle Transactions

In 2014, Enbridge and EEP undertook a series of actions with the objective of enhancing EEP's distributable cash flow and returns generated by investment opportunities and to increase its effectiveness as a sponsored vehicle and source of funding for Enbridge via future asset monetization.

Proposed Alberta Clipper Drop Down

In September 2014, Enbridge and EEP announced Enbridge's proposal to transfer its current 66.7% interest in the United States segment of the Alberta Clipper pipeline, currently held through a wholly-owned Enbridge subsidiary in the United States, to EEP for approximately US$900 million. EEP currently owns the other 33.3% interest in Alberta Clipper. The proposed consideration includes cash of approximately US$300 million, plus approximately US$600 million in Class E equity units to be issued to Enbridge by EEP. The proposed transfer and terms are subject to review and recommendation by an independent committee of EEP. The transfer is targeted to close by the end of 2014.

The Class E units to be issued to Enbridge would be entitled to the same distributions as the Class A units held by the public and would be convertible into Class A units on a one-for-one basis at Enbridge's option. The Class E units would be redeemable at EEP's option after 30 years, if not converted by Enbridge. The units would have a liquidation preference equal to their fair value on closing. Enbridge's economic interest in EEP would increase from approximately 34% to approximately 36% as a result of the transfer.

The United States segment of the Alberta Clipper Pipeline is a 36-inch diameter, 523-kilometre (325-mile) long crude oil pipeline from the United States border near Neche, North Dakota to Superior, Wisconsin. The initial capacity of the line is 450,000 barrels per day (bpd) and was constructed under the terms of a joint funding agreement under which Enbridge funded two-thirds of the capital costs in return for a corresponding economic interest in the earnings and cash flow from the investment. The line is being expanded in two phases to a capacity of 800,000 bpd through the addition of increased pumping horsepower. The required expansion investments are subject to separate joint funding arrangements between Enbridge and EEP. See *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

Equity Restructuring

In June 2014, EEP and Enbridge announced an agreement to restructure EEP's equity. Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly-owned subsidiary of Enbridge and the General Partner (GP) of EEP, irrevocably waived its then existing incentive distribution rights (IDR) in excess of its 2% GP interest in exchange for 66.1 million Class D units and 1,000 Incentive Distribution Units (IDU) (collectively, the Equity Restructuring). The GP share of incremental cash distributions decreased from 48% of all distributions in excess of US$0.4950 per unit per quarter down to 23% of all distributions in excess of EEP's quarterly distribution of US$0.5435 per unit per quarter. The Class D units carry a distribution equal to the quarterly distribution on the Class A common units. The third quarter 2014 distribution on the Class D units were adjusted to provide Enbridge with an aggregate distribution in 2014 equal to the distribution on its IDR as if the Equity Restructuring had not occurred. The IDU is not entitled to a distribution initially and in the event of any decrease in the Class A common unit distribution below US$0.5435 per unit in any quarter during the next five years, the distribution on the Class D units will be reduced to the amount which would have been received by Enbridge under the IDR as if the Equity Restructuring had not occurred.

The Class D units have a notional value per unit equivalent to the closing market price of the Class A Common units on June 17, 2014 (Notional Value) and have the same voting rights as the Class A units. The Class D units are convertible on a one-for-one basis into Class A common units at any time on or after the fifth anniversary of the closing date, at the holder's option. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D unitholders will have a preference in liquidation equal to 20% of the Notional Value, with such preference being increased by an additional 20% on each anniversary of the closing date, resulting in a liquidation preference equal to 100% of the Notional Value on the fourth anniversary of the closing date. The Class D units will be redeemable in 30 years in whole or in part at EEP's option for either a cash amount equal to the Notional Value per unit or newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate Notional Value of the Class D units being redeemed.

EEP Drop Down of Additional Interest to Midcoast Energy Partners, L.P.

On July 1, 2014, EEP completed the sale of an additional 12.6% limited partnership interest in its natural gas and NGL midstream business to MEP for cash proceeds of US$350 million. Upon finalization of this transaction, EEP retains an approximate 48% direct interest in entities or partnerships holding the natural gas and NGL midstream operations, with the remaining ownership held by MEP. The balance of EEP's interest in the natural gas and NGL midstream operations is held indirectly through ownership of a GP interest, an approximate 52% limited partner interest and all IDR of MEP. The completion of this transaction resulted in a partial monetization of EEP's natural gas and NGL midstream business through sale to noncontrolling interests (being MEP's public unitholders). The proceeds from the drop down provided EEP a cost-effective funding alternative to execute its current liquids pipeline organic growth program.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA.

EEP is also working with the Michigan Department of Environmental Quality (MDEQ) to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at September 30, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($198 million after-tax attributable to Enbridge), which is an increase of US$86 million ($17 million after-tax attributable to Enbridge) as compared with December 31, 2013 and an increase of US$51 million ($12 million after-tax attributable to Enbridge) as compared with June 30, 2014. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. Of the total cost increase of US$51 million during the three months ended September 30, 2014, US$33 million is primarily related to the MDEQ approved Schedule of Work and completion of the dredge activities near Ceresco and Morrow Lake and US$18 million is related to an increase of estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates 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. Including EEP's remediation spending through September 30, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at September 30, 2014, 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 for the then remaining US$145 million 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 payment of US$42 million from the other remaining insurers. Of the remaining US$103 million coverage limit, US$85 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing EEP's recovery eligibility for costs related to its claim on the Line 6B crude oil release. The recovery of the remaining US$18 million is awaiting resolution of this lawsuit. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event 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 10 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.

At September 30, 2014, 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$3.7 million related to civil penalties assessed by the Pipeline and Hazardous Materials Safety Administration, which EEP paid during the third quarter of 2012. The total also included an amount of US$40 million related to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$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 measures directed toward enhancing spill prevention, leak detection, emergency response to environmental events and the cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

SPONSORED INVESTMENTS – ENBRIDGE INCOME FUND

Proposed Natural Gas And Diluent Pipeline Interests Transfer

In September 2014, Enbridge and the Fund announced that they had entered into an agreement pursuant to which the Fund would acquire Enbridge's 50% interest in the United States segment of the Alliance Pipeline and would also subscribe for and purchase Class A units of Enbridge's subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline. The Class A units, which are non-voting and do not confer any governance or ownership rights in Southern Lights Pipeline, will provide a defined cash flow stream to the Fund. Total consideration for the proposed transaction is approximately $1.8 billion. Enbridge will receive on closing approximately $421 million in cash and $461 million in the form of preferred units of Enbridge Commercial Trust, a subsidiary of the Fund. Under the agreement, Enbridge has agreed to provide bridge debt financing to the Fund in the form of an $878 million long-term note payable by the Fund and bearing interest of 5.5% per annum. The note payable is expected to be repaid by the Fund on an expedited basis through the issuance of public debt by the Fund. The Fund will also issue $421 million of trust units to Enbridge Income Fund Holdings Inc. (ENF) to fund the cash component of the consideration. Enbridge will apply approximately $84 million of cash to acquire additional common share of ENF, thereby maintaining its 19.9% interest in ENF. The transaction is subject to customary regulatory approvals, including pursuant to competition legislation in Canada and the United States. If approved, the transaction is expected to provide Enbridge approximately $1.2 billion of net funding for its large growth capital investment program. The transaction is expected to close in the fourth quarter of 2014.

CORPORATE

Preference Share Issuance

Series 9

On March 13, 2014, the Company issued 11 million Preference Shares, Series 9 for gross proceeds of $275 million. The 4.4% Cumulative Redeemable Preference Shares, Series 9 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 9 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 10, subject to certain conditions, on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 10 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Series 11

On May 22, 2014, the Company issued 20 million Preference Shares, Series 11 for gross proceeds of $500 million. The 4.4% Cumulative Redeemable Preference Shares, Series 11 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on March 1, 2020 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 11 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 12, subject to certain conditions, on March 1, 2020 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 12 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.6%.

Series 13

On July 17, 2014, the Company issued 14 million Preference Shares, Series 13 for gross proceeds of $350 million. The 4.4% Cumulative Redeemable Preference Shares, Series 13 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 13 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 14, subject to certain conditions, on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 14 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Series 15

On September 23, 2014, the Company issued 11 million Preference Shares, Series 15 for gross proceeds of $275 million. The 4.4% Cumulative Redeemable Preference Shares, Series 15 are entitled to receive a fixed, cumulative, quarterly preferential dividend aggregating to $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on September 1, 2020 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 15 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 16, subject to certain conditions, on September 1, 2020 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 16 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Common Share Issuance

On June 24, 2014, the Company completed the issuance of 7.9 million Common Shares for gross proceeds of approximately $400 million and, on July 8, 2014, issued a further 1.2 million Common Shares pursuant to the underwriters' over-allotment option for gross proceeds of approximately $60 million. The proceeds will be used to partially fund the Company's capital projects, including the Line 3 Replacement Program (L3R Program), to reduce short term indebtedness and for other general corporate purposes. For further discussion on the L3R Program refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Canadian Line 3 Replacement Program* and *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – United States Line 3 Replacement Program*.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Seaway Crude Pipeline System Twinning/Extension	US$1.2 billion	US$1.1 billion	2014	Substantially complete
2. Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.6 billion	2013-TBD[3] (in phases)	Under construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
3. Eddystone Rail Project	US$0.1 billion	US$0.1 billion	2014	Complete
4. Norealis Pipeline	$0.5 billion	$0.5 billion	2014	Complete
5. Flanagan South Pipeline Project	US$2.8 billion	US$2.7 billion	2014	Substantially complete
6. Canadian Mainline Expansion	$0.7 billion	$0.3 billion	2015	Under construction
7. Surmont Phase 2 Expansion	$0.3 billion	$0.2 billion	2014-2015 (in phases)	Under construction
8. Sunday Creek Terminal Expansion	$0.2 billion	$0.1 billion	2015	Under construction
9. Woodland Pipeline Extension	$0.6 billion	$0.4 billion	2015	Under construction
10. Edmonton to Hardisty Expansion	$1.8 billion	$0.7 billion	2015	Under construction
11. Southern Access Extension	US$0.6 billion	US$0.2 billion	2015	Pre-construction
12. AOC Hangingstone Lateral	$0.2 billion	No significant expenditures to date	2015	Pre-construction
13. Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.3 billion	2013-2015 (in phases)	Under construction
14. JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
15. Athabasca Pipeline Twinning	$1.2 billion	$1.0 billion	2017	Under construction
16. Wood Buffalo Extension	$1.6 billion	$0.1 billion	2017	Pre-construction
17. Norlite Pipeline System[4]	$1.4 billion	No significant expenditures to date	2017	Pre-construction
18. Canadian Line 3 Replacement Program	$4.9 billion	$0.1 billion	2017	Pre-construction
GAS DISTRIBUTION				
19. Greater Toronto Area Project	$0.7 billion	$0.1 billion	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
20. Pipestone and Sexsmith Project	$0.3 billion	$0.3 billion	2012-2014 (in phases)	Complete
21. Blackspring Ridge Wind Project	$0.3 billion	$0.3 billion	2014	Complete
22. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2015 (in phases)	Under construction
23. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2015	Under construction
24. Keechi Wind Project	US$0.2 billion	US$0.1 billion	2015	Under construction
25. Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
26. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Under construction
SPONSORED INVESTMENTS				
27. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Complete

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
28. EEP - Eastern Access[5]	US$2.7 billion	US$2.0 billion	2013-2016 (in phases)	Under construction
29. EEP - Lakehead System Mainline Expansion[5]	US$2.3 billion	US$0.8 billion	2014-2016 (in phases)	Under construction
30. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	US$0.1 billion	2015	Under construction
31. EEP - Sandpiper Project[6]	US$2.6 billion	US$0.2 billion	2017	Pre-construction
32. EEP - U.S. Line 3 Replacement Program	US$2.6 billion	US$0.2 billion	2017	Pre-construction

1 These amounts are estimates and subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge's share of joint venture projects.

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to September 30, 2014.

3 Enbridge is currently working with the National Energy Board to provide the information needed to satisfy a National Energy Board condition in relation to the Line 9 Reversal and Expansion project. As a result, the Company is unable to estimate the length of the delay to the expected in-service date.

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

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

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

LIQUIDS PIPELINES

Seaway Pipeline

Enbridge holds a 50% interest in the Seaway Pipeline which includes an 805-kilometre (500-mile) 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas.

Reversal and Expansion

The flow direction of the Seaway Pipeline was reversed in 2012, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in 2013, increasing capacity available to shippers to up to approximately 400,000 bpd, depending on crude oil slate.

Twinning and Extension

A second line was constructed in order to more than double the existing capacity of the Seaway Pipeline to approximately 850,000 bpd and was mechanically completed in July 2014. Line fill on the Seaway Pipeline twinning is expected to follow the completion of line fill on the Flanagan South Pipeline (Flanagan South). See *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Flanagan South Pipeline Project.* This 30-inch diameter pipeline follows the same route as the existing Seaway Pipeline and was constructed to meet additional capacity commitments from shippers. Included in the project scope is the 105-kilometre (65-mile), 36-inch diameter pipeline lateral from the Seaway Jones Creek facility southwest of Houston, Texas to Enterprise Product Partners L.P.'s ECHO crude oil terminal (ECHO Terminal) in Houston, Texas. The lateral was placed into service in January 2014.

In addition, a 161-kilometre (100-mile) pipeline was constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining centre to provide shippers access to the region's heavy oil refining capabilities. This extension was mechanically completed in August 2014 and provides capacity of 750,000 bpd.

Including the acquisition of the initial 50% interest, Enbridge's total expected cost for the Seaway Pipeline is now approximately US$2.5 billion. The acquisition, reversal and expansion were completed at an approximate cost of US$1.3 billion, with the twinning, extension and lateral components of the project expected to cost approximately US$1.2 billion. Total expenditures incurred to date are approximately US$2.4 billion.

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 partial reversal of Line 9A, a full reversal and expansion of Line 9B and expansion of the Toledo Pipeline. 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*.

In 2013, Enbridge completed the 80,000 bpd expansion of its Toledo Pipeline (Line 17), which connects with the EEP mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan. The project was completed at an approximate cost of US$0.2 billion.

In 2013, Enbridge also completed the reversal of a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Enbridge is also undertaking a full reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in that province. The Line 9B reversal was 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 within Ontario and Quebec, resulting in the Line 9B capacity expansion project. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

Both the Line 9B reversal and Line 9B 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 9B capacity expansion projects. On October 23, 2014, Enbridge responded to the NEB describing the Company's rigorous approach to risk management and isolation valve placement. Enbridge is currently awaiting response from the NEB to determine whether additional information is needed to satisfy the condition prior to applying for a Leave to Open allowing the operation of the project. As a result of the current discussions, the Company is unable to estimate the length of delay to the in-service date for the Line 9B reversal and Line 9B capacity expansion projects. 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 discussed Line 9A reversal. Enbridge is currently in discussions with shippers to recover the incremental costs of Line 9B through tolls. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.6 billion.

Eddystone Rail Project

In April 2014, under a joint venture agreement with Canopy Prospecting Inc., the Company completed the development of a unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania to deliver Bakken and other light sweet crude oil to Philadelphia area refineries. The Eddystone Rail Project (Eddystone) included leasing portions of a power generation facility and involved replacing and twinning the existing track to accommodate 120-car unit-trains, installing crude oil offloading equipment, refurbishing an existing 200,000 barrel tank and upgrading an existing barge loading facility. Eddystone is capable of receiving and delivering an initial capacity of 80,000 bpd, and could be expanded to 160,000 bpd. Based on its 75% joint venture interest, Enbridge's investment in the project was approximately US$0.1 billion.

Norealis Pipeline

In order to provide pipeline and terminalling services to the Husky Energy Inc. operated Sunrise Energy Project that is currently under development, Enbridge constructed a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline from the Norealis Terminal to the Cheecham Terminal and additional tankage at Cheecham. The Norealis Pipeline project was completed in April 2014 at a total cost of approximately $0.5 billion. Enbridge expects to receive first oil in the fourth quarter of 2014, commensurate with the start-up of the Sunrise Energy project.

Flanagan South Pipeline Project
The 950-kilometre (590-mile) pipeline has an initial design capacity of approximately 600,000 bpd; however, in the initial years it is not expected to operate at its full design capacity. Flanagan South will transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline is installed adjacent to the Company's Spearhead Pipeline for the majority of the route. The pipeline is now mechanically completed and line fill arrangements have begun and will continue throughout November 2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$2.7 billion.

The Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court) in August 2013. The Complaint was filed against multiple federal agencies (the Defendants) and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. Enbridge obtained intervenor status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction in September 2013. The Plaintiff's request for preliminary injunction was denied by the Court in November 2013. A court hearing was held on February 21, 2014 concerning the merits of the Complaint against the Defendants, and on August 18, 2014, the Court ruled to dismiss all claims in favour of Enbridge and the Defendants. The Plaintiffs filed an appeal to the United States Court of Appeals for the District of Columbia Circuit.

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 which 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 mechanically completed in the third quarter of 2014 at an estimated capital cost of approximately $0.2 billion. Delays in receipt of the applicable regulatory approvals on EEP's portion of the mainline system expansion are expected to delay the full operation of the first phase of the Canadian Mainline Expansion. However, a number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase. See *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

The second phase to increase capacity from 570,000 bpd to 800,000 bpd is expected to be placed into service in 2015. The second phase is expected to cost approximately $0.5 billion following the completion of a detailed engineering review conducted in the first quarter of 2014. The revised estimate reflected enhanced tanking, terminalling and connectivity to optimize pipeline operation at the full 800,000 bpd design capacity. The estimated cost of the entire expansion is approximately $0.7 billion, with expenditures to date of approximately $0.3 billion.

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 is constructing two new 450,000 barrel blend tanks and converting an existing tank from blend to diluent service. The expansion is expected to come into service in two phases, with the blended product system expected in the fourth quarter of 2014 and the diluent system expected in the first quarter of 2015. The estimated cost of the project is approximately $0.3 billion with expenditures to date of approximately $0.2 billion.

Sunday Creek Terminal Expansion
In January 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 $0.1 billion and a targeted in-service date of 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 approximately $0.6 billion, with expenditures incurred to date of approximately $0.4 billion. Subject to finalization of scope and a definitive cost estimate, 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 will include 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 is expected to generally follow 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 which include five new 500,000 barrel tanks. The new pipeline is expected to be placed into service in the first quarter of 2015, with additional tankage requirements expected to be completed in the fourth quarter of 2015, all at an expected total cost of approximately $1.8 billion. Expenditures incurred to date are approximately $0.7 billion.

Southern Access Extension
The Southern Access Extension project (Southern Access Extension) will involve 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. Effective July 1, 2014, the Company entered into an agreement with Lincoln Pipeline LLC (Lincoln), an affiliate of Marathon Petroleum Corporation (MPC), to, among other things, admit Lincoln as a partner and participate in Southern Access Extension. Lincoln has purchased a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension spend profile in proportion to its 35% interest. Subject to regulatory and other approvals, the project is now expected to be placed into service in late 2015. Southern Access Extension is expected to cost approximately US$0.9 billion, with Enbridge’s share of the estimated capital cost expected to be approximately US$0.6 billion. Enbridge’s expenditures to date on the project are 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. Phase I of the project will provide an initial capacity of 16,000 bpd and is now expected to be placed into service in the fourth quarter of 2015, to align with shipper volume availability, now at an estimated cost of approximately $0.2 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.

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, additional booster pumps and new tank line connections. These projects have varying completion dates from 2013 through 2015. The cost of the project is expected to be approximately $0.7 billion following the completion of a detailed engineering review. The revised estimate reflects enhanced tankage, terminalling and connectivity in conjunction with the Company's Canadian Mainline Expansion project. Refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Canadian Mainline Expansion*. Expenditures to date total approximately $0.3 billion.

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. Subject to regulatory approvals, 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 will provide capacity of 40,000 bpd at an estimated cost of approximately $0.1 billion and is expected to enter service in 2016.

Athabasca Pipeline Twinning
This project involves twinning the southern section of the Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to provide additional capacity to serve expected oil sands growth in the Kirby Lake producing region. The expansion project, with an estimated cost of approximately $1.2 billion, and expenditures to date of approximately $1.0 billion, will include 346 kilometres (215 miles) of 36-inch diameter pipeline adjacent to the existing Athabasca Pipeline right-of-way. The line is expected to be delayed beyond its original in-service date and is now expected to be completed in 2017 due to a change in the construction schedule to align with shipper volume availability.

Wood Buffalo Extension
In 2013, Enbridge was selected by Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), as well as the Suncor Energy Oil Sands Limited Partnership (Suncor Partnership), to develop a new pipeline to transport crude oil production to Enbridge's mainline hub at Hardisty, Alberta. The proposed Wood Buffalo Extension will extend Enbridge's existing Wood Buffalo Pipeline and includes construction of a new 450-kilometre (281-mile) 30-inch pipeline from Enbridge's Cheecham Terminal to its Battle River Terminal at Hardisty, as well as associated terminal upgrades. The completed project will provide capacity of 490,000 bpd of diluted bitumen to be transported for the proposed Fort Hills Partners' oil sands project (Fort Hills Project) in northeastern Alberta and Suncor Partnership's oil sands production in the Athabasca region. Subject to regulatory approvals, the project is expected to be completed in 2017 at an estimated cost of approximately $1.6 billion, with expenditures incurred to date of approximately $0.1 billion.

Norlite Pipeline System
Enbridge is undertaking the development of Norlite Pipeline System (Norlite), a new industry diluent pipeline originating from Edmonton 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 and Stonefell 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 expected to be completed in 2017 at an estimated cost of approximately $1.4 billion.

Canadian Line 3 Replacement Program

In March 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the 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 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 $0.1 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 will undertake 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 will involve 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. With the OEB approval received in January 2014, construction is targeted to start in late 2014. The project is expected to be completed by the end of 2015 at an estimated cost of approximately $0.7 billion, with expenditures to date of approximately $0.1 billion.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Pipestone and Sexsmith Project

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities located in the Peace River Arch (PRA) region of northwest Alberta (collectively, Pipestone and Sexsmith). These facilities were either in service (Sexsmith) or under construction (Pipestone) at the time of acquisition. Construction of new gathering lines and NGL handling facilities was completed in June 2014. Enbridge's investment in Pipestone and Sexsmith is approximately $0.3 billion. Enbridge also retains an exclusive right to work with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region.

Blackspring Ridge Wind Project

In 2013, Enbridge secured a 50% interest in the development of the 300-MW Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project was constructed under a fixed price engineering, procurement and construction contract and commercial operations commenced in May 2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity is being sold into the Alberta power pool with pricing fixed on 75% of production through long-term price swap arrangements. The Company's total investment in the project is approximately $0.3 billion.

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 meters (7,000 feet) with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS is now expected to be placed into service in the first quarter of 2015 and the Big Foot Oil Pipeline (Big Foot Pipeline) portion is now expected to be placed into service in the fourth quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., 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$0.1 billion. As noted above, the Big Foot Pipeline is now expected to enter service in the fourth quarter of 2015.

Keechi Wind Project

In January 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-MW Keechi Wind Project (Keechi), located in Jack County, Texas, at an investment of approximately US$0.2 billion, with expenditures incurred to date of approximately US$0.1 billion. RES Americas is constructing the wind project under a fixed price, engineering, procurement and construction agreement, with expected completion in the first quarter of 2015. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year power purchase agreement with Microsoft Corporation.

Aux Sable Extraction Plant Expansion

In October 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 System (Alliance System), allow for the effective management of Alliance System's downstream natural gas heat content and for 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 Lateral 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. The Heidelberg Lateral Pipeline (Heidelberg), 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 is expected to be operational by 2016 at an approximate cost of US$0.1 billion.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Line 6B 75-Mile Replacement Program

The Line 6B 75-Mile Replacement Program included the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP's Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments were completed in components, with approximately 104 kilometres (65 miles) of segments placed in service in 2013. The two remaining 8-kilometre (5-mile) segments in Indiana were placed in service in March 2014. The total cost of the replacement program was approximately US$0.4 billion and EEP is recovering these costs through a tariff surcharge that is part of the system-wide rates for the Lakehead System.

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 EEP include an expansion of its Line 5 and expansions of the United States mainline involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. For discussion on Enbridge's portion of Eastern Access refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Eastern Access*.

In 2013, EEP completed and placed into service the expansion of its Line 5 light crude oil line between Superior, Wisconsin and the international border at the St. Clair River. The Line 5 expansion increased capacity by 50,000 bpd at an approximate cost of US$0.1 billion. Also in 2013, EEP completed and placed into service the expansion of Line 62 between Flanagan, Illinois and Griffith, Indiana, which increased capacity by 105,000 bpd.

EEP also replaced additional sections of Line 6B in Indiana and Michigan, which included the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline were also replaced with 36-inch diameter pipe. The Line 6B project is split into two phases. The segment between Griffith and Stockbridge was completed in May 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River was completed in September 2014. The replacement of the Line 6B sections is in addition to the Line 6B 75-mile Replacement Program discussed previously. Following detailed engineering estimates completed in the first quarter of 2014 which reflect issues with local ground terrain conditions including tie-ins, the expected cost of the United States mainline expansions is approximately US$2.4 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

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 Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. Following the completion, in the first quarter of 2014, of a detailed engineering estimate and a scope revision that removed a proposed tank, the total cost of the project is approximately US$0.3 billion. The project is expected to be placed into service in early 2016.

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative, including the United States mainline expansions, the Line 5 expansion and the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$2.0 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 includes the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61).

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. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower and no pipeline construction. 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, the initial phase was mechanically completed in the third quarter of 2014 and the second phase is expected to be in-service in 2015. It is now anticipated that obtaining regulatory approval will take longer than originally planned though approval is expected in mid-2015. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. 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 and Flanagan to increase capacity from 560,000 bpd to 1,200,000 bpd. Following completion of a more detailed engineering estimate in the first quarter of 2014, the second phase of the Southern Access expansion is expected to cost approximately US$1.2 billion. Both phases of the expansion require only the addition of pumping horsepower and crude oil tanks at existing sites, with no pipeline construction. For the second phase of the expansion, which remains subject to regulatory and other approvals, the pump stations are expected to be available for service in the third quarter of 2015, with additional tankage requirements expected to be completed in early 2016.

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$0.8 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Beckville Cryogenic Processing Facility
EEP and its partially-owned subsidiary 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 expected to be placed into service in the first quarter of 2015 at an estimated cost of approximately US$0.1 billion. 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 the Sandpiper project (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$0.2 billion.

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, now targeted for 2017 due to a longer than expected permitting process in the State of Minnesota.

A petition was filed with the FERC to approve recovery of Sandpiper's costs through a surcharge to the NDPC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. In March 2013, the FERC denied the petition on procedural grounds. In late 2013, EEP held an open season to solicit commitments from shippers for capacity created by Sandpiper. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity identified above. EEP re-filed its petition with the FERC on February 12, 2014 and received a FERC declaratory order in May 2014 approving the tariffs structure for the project. The pipeline is now expected to begin service in 2017, subject to obtaining regulatory and other approvals.

United States Line 3 Replacement Program

In March 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 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.

GROWTH PROJECTS – OTHER 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 which 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

Northern Gateway Project (Northern Gateway) involves constructing a twin 1,177-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.

On December 19, 2013, the Joint Review Panel (JRP) issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living and noted that the benefits of Northern Gateway outweigh its burdens and that "Canadians would be better off with the Enbridge Northern Gateway Project than without it." The JRP recommended to the Governor in Council that Certificates of Public Convenience and Necessity (Certificates) for the oil and condensate pipelines, incorporating the terms and conditions in their report, be issued to Northern Gateway pursuant to Part III of the NEB Act. The Government of Canada has consulted with Aboriginal groups on the JRP report and its recommendations prior to making its decision on whether to direct the NEB to issue the certificates for the pipelines.

On June 17, 2014, the Governor in Council issued an Order in Council approving the JRP recommendation, including all 209 recommended conditions. The NEB issued the Certificates for the oil and condensate pipelines on June 18, 2014.

Nine applications 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 of Appeal (Federal Court) granted leave to all nine applications. Based on discussions between counsel for the various parties involved, the Company expects that the applications will be consolidated into a single proceeding, and for these judicial proceedings to be completed in the first half of 2015 with a decision from the Federal Court expected by late 2015.

In October 2014, the Company reviewed an updated cost estimate of Northern Gateway based on full engineering analysis of the pipeline route and terminal location. Based on this comprehensive review, the Company expects that the final cost of the project will be substantially higher than the preliminary cost figures included in the Northern Gateway filing with the JRP, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. The updated cost estimate is currently being refined by Northern Gateway and the potential shippers.

Subject to continued commercial support, regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company now 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. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so.

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

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES
NEXUS Gas Transmission Project
In 2012, Enbridge, DTE Energy Company (DTE) and Spectra Energy Corp. (Spectra) announced the execution of a Memorandum of Understanding (MOU) to jointly develop the NEXUS Gas Transmission System, a project that would move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan, and Ontario, Canada. The MOU has expired and Enbridge is in discussions with Spectra and DTE regarding the terms of its continued participation in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Canadian Mainline	**128**	112	**400**	341
Regional Oil Sands System	**44**	38	**134**	115
Southern Lights Pipeline	**13**	15	**37**	36
Seaway Pipeline	**16**	9	**39**	38
Spearhead Pipeline	**9**	8	**27**	25
Feeder Pipelines and Other	**11**	5	**22**	10
Adjusted earnings	**221**	187	**659**	565
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(231)**	133	**(192)**	(125)
Canadian Mainline - Line 9B costs incurred during reversal	**(2)**	-	**(6)**	-
Regional Oil Sands System - make-up rights adjustment	**5**	-	**5**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	(37)	**-**	(37)
Regional Oil Sands System - leak insurance recoveries	**-**	-	**4**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(4)**	(13)	**(4)**	(53)
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	31	**-**	31
Southern Lights Pipeline - changes in unrealized derivative fair value loss	**(9)**	-	**(9)**	-
Seaway Pipeline - make-up rights adjustment	**(11)**	-	**(11)**	-
Spearhead Pipeline - make-up rights adjustment	**-**	-	**(1)**	-
Feeder Pipelines and Other - make-up rights adjustment	**1**	-	**3**	-
Feeder Pipelines and Other - project development costs	**(1)**	-	**(4)**	-
Earnings/(loss) attributable to common shareholders	**(31)**	301	**444**	381

Canadian Mainline
Canadian Mainline adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the respective 2013 comparative periods. Trends experienced in the first half of 2014 continued into the third quarter of 2014. Adjusted earnings growth was primarily driven by higher throughput with several factors contributing to the increase including: increased oil sands production; 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; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Higher terminalling revenues and lower operating and administrative costs during the first half of 2014 were also positive contributors to adjusted earnings growth.

Partially offsetting these positive impacts was a lower average Canadian Mainline IJT Residual Benchmark Toll for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which on average was higher throughout 2014 due to the recovery of incremental costs associated with EEP's growth projects. Higher power costs associated with incremental throughput as well as higher depreciation from an increased asset base also impacted adjusted earnings in 2014. Finally, Canadian Mainline adjusted earnings for 2014 continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013 and is being reversed and expanded as part of the Company's Eastern Access initiative. For further information on Line 9B refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Eastern Access.*

Supplemental information on Canadian Mainline adjusted earnings for the three and nine months ended September 30, 2014 and 2013 is provided below.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Revenues	**366**	353	**1,121**	1,064
Expenses				
Operating and administrative	**99**	90	**282**	303
Power	**41**	31	**117**	86
Depreciation and amortization	**67**	62	**198**	180
	207	183	**597**	569
	159	170	**524**	495
Other income/(expense)	**6**	(3)	**4**	1
Interest expense	**(40)**	(42)	**(118)**	(122)
	125	125	**410**	374
Income taxes recovery/(expense)	**3**	(13)	**(10)**	(33)
Adjusted earnings	**128**	112	**400**	341
Effective United States to Canadian dollar exchange rate[1]	**1.016**	1.000	**1.019**	0.999

As at September 30,	**2014**	2013
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$4.02**	$3.98
Lakehead System Local Toll[3]	**$2.49**	$2.18
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.53**	$1.80

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. Effective January 1, 2014, the Lakehead System Local Toll decreased from US$2.18 to US$2.17. 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 Local Toll increased from US$2.17 to US$2.49 per barrel.*

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 January 1, 2014, this toll increased from US$1.80 to US$1.81. This toll increased to US$1.85 effective July 1, 2014 and subsequently decreased to US$1.53 effective August 1, 2014, coinciding with the revised Lakehead System Local Toll.*

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
Throughput[1] *(thousand barrels per day (kbpd))*	**2,039**	1,736	**1,970**	1,707

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

Regional Oil Sands System
Regional Oil Sands System adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings growth was primarily driven by contributions from the Norealis Pipeline which was completed in April 2014, as well as higher throughput on the Athabasca mainline. Partially offsetting the increase in adjusted earnings were higher depreciation expense from a larger asset base and higher operating and administrative, interest and tax expenses from increased operational activities.

Seaway Pipeline
Seaway Pipeline adjusted earnings for the nine months ended September 30, 2014 were comparable with the equivalent 2013 period, however, due to offsetting factors. Adjusted earnings increased due to higher average tolls, offset by higher operating and financing costs. Seaway Pipeline adjusted earnings for the third quarter of 2014 reflected a make-up rights adjustment related to the first half of 2014. Excluding the impact of the make-up rights adjustment, quarter-over-quarter adjusted earnings were comparable and reflected the same trends noted in the nine-month period comparison.

Feeder Pipelines and Other
Feeder Pipelines and Other adjusted earnings for the three and nine month period ended September 30, 2014 were higher compared with the same periods of 2013 due to lower business development costs not eligible for capitalization, a combination of higher tolls and throughput on the Toledo Pipeline and the incremental earnings from Eddystone completed in April 2014. Partially offsetting the increase in earnings were lower average tolls on Olympic Pipeline.

Liquids Pipelines earnings/(loss) were impacted by the following adjusting items:
- Canadian Mainline earnings/(loss) for each period reflected changes in unrealized fair value gains and 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 earnings/(loss) for 2014 included depreciation and interest expenses charged to Line 9B while it was idled and undergoing a reversal as part of the Company's Eastern Access initiative.
- Regional Oil Sands System earnings for the third quarter of 2014 included a make-up rights adjustment.
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts.
- Regional Oil Sands System earnings for 2014 included insurance recoveries associated with the Line 37 crude oil release which occurred in June 2013.
- Regional Oil Sands System earnings for 2014 and 2013 included charges related to the Line 37 crude oil release which occurred in June 2013.
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to correct deferred income tax expense and to correct the rate at which deemed taxes are recovered under a long-term contract.
- Southern Lights Pipeline earnings for 2014 included an unrealized fair value loss on derivative financial instruments.
- Seaway Pipeline earnings for 2014 included a make-up rights adjustment.
- Spearhead Pipeline earnings for 2014 included a make-up rights adjustment.
- Feeder Pipelines and Other earnings for 2014 included a make-up rights adjustment.
- Feeder Pipelines and Other earnings for 2014 included certain business development costs related to Northern Gateway that are anticipated to be recovered over the life of the project.

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**(3)**	(26)	**100**	97
Other Gas Distribution and Storage	**(6)**	(3)	**9**	12
Adjusted earnings/(loss)	**(9)**	(29)	**109**	109
EGD - (warmer)/colder than normal weather	**(2)**	-	**35**	(4)
EGD - gas transportation costs out-of-period adjustment	**-**	(56)	**-**	(56)
Earnings/(loss) attributable to common shareholders	**(11)**	(85)	**144**	49

EGD adjusted earnings reflected the impact of the OEB decision on EGD's IR mechanism which was approved with modifications by the OEB on July 17, 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB Rate Order under the IR mechanism approved the final rates with an effective date of January 1, 2014.

EGD adjusted earnings increased slightly for the nine months ended September 30, 2014 compared with the equivalent 2013 period and reflected customer growth, as well as the impacts of the Rate Order. The Rate Order approved a new approach for determining depreciation and future removal and site restoration reserves which resulted in a lower depreciation expense for the nine months ended September 30, 2014. This positive effect was partially offset by reduced rates under the Rate Order, with an effective date of January 1, 2014, requiring a refund of a portion of the previously collected interim rates to customers which was also reflected in the third quarter of 2014. Also partially offsetting the adjusted earnings increase was higher interest expense due to an increase in external debt issued in 2014.

EGD adjusted loss for the third quarter of 2014 decreased compared with the corresponding 2013 three-month period. EGD 2013 third quarter adjusted loss included a gas transportation adjustment related to the first half of 2013. Excluding the impact of the gas transportation adjustment, EGD 2014 third quarter adjusted loss was lower compared with the adjusted loss for the comparative period and reflected similar trends as the year-to-date results noted above.

Adjusted earnings from Other Gas Distribution and Storage for the nine months ended September 30, 2014 included a loss from EGNB related to 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. This contract expired in October 2014 and will not have an impact to adjusted earnings for the remainder of the year.

Gas Distribution earnings/(loss) were impacted by the following adjusting items:

- EGD earnings/(loss) were adjusted to reflect the impact of weather. Included in EGD adjusted earnings for the third quarter of 2014 was an adjustment to reflect weather normalization under lower distribution rates from the OEB approved Rate Order under the IR mechanism. Refer to *Recent Developments – Gas Distribution – Enbridge Gas Distribution – Incentive Regulation.*
- EGD earnings/(loss) for 2013 reflected an out-of-period correction to gas transportation costs which had previously been deferred.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Aux Sable	**9**	16	**20**	32
Energy Services	**(3)**	19	**27**	94
Alliance Pipeline US	**12**	10	**36**	31
Vector Pipeline	**3**	5	**12**	18
Enbridge Offshore Pipelines (Offshore)	**(3)**	(4)	**(3)**	(4)
Other	**2**	8	**14**	15
Adjusted earnings	**20**	54	**106**	186
Energy Services - changes in unrealized derivative fair value gains	**71**	18	**288**	131
Offshore - changes in unrealized derivative fair value loss	**(2)**	-	**(2)**	-
Offshore - gain on sale of non-core assets	**-**	-	**43**	-
Other - changes in unrealized derivative fair value loss	**(1)**	(4)	**(3)**	(60)
Earnings attributable to common shareholders	**88**	68	**432**	257

Aux Sable earnings decreased for the three and nine months ended September 30, 2014 compared with the 2013 comparative periods and reflected lower fractionation margins partially offset by an increase in propane volumes produced at the Channahon Plant, lower volumes at upstream processing plants and higher administrative expense.

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. Adjusted earnings for the third quarter of 2014 decreased compared with the third quarter of 2013 due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges. The trends noted above which also negatively impacted the first half of 2014 are expected to continue into the fourth quarter of 2014.

Energy Services adjusted earnings for the nine months ended September 30, 2014 were lower compared with the very strong comparative 2013 period. In addition to the factors noted above, losses were 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. Partially offsetting the decrease in the adjusted earnings were favourable natural gas location differentials caused by abnormal winter weather conditions during the first quarter of 2014. Adjusted earnings from Energy Services are dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Alliance Pipeline US earnings increased in both the three and nine months ended September 30, 2014 compared with the equivalent 2013 periods due to an increase in depreciation expense recovered in tolls as well as earnings from the Tioga Lateral which was placed into service in September 2013.

Vector Pipeline earnings in the three and nine months ended September 30, 2014 decreased compared with the comparative periods of 2013 and reflected lower depreciation expense recognized in tolls. For the nine months ended September 30, 2014, the decrease in earnings was partially offset by higher uncommitted transportation volumes and prices. Higher volumes were primarily driven by increased demand for natural gas in eastern North America in response to abnormal winter weather conditions experienced in the first quarter of 2014.

Offshore adjusted loss for the three and nine months ended September 30, 2014 reflected persistent weak volumes within Offshore's corridor due to decreased production in the Gulf of Mexico. Offshore adjusted earnings are expected to remain weak, until such time as the WRGGS and the Big Foot Pipeline are placed into service, which are expected in the first and fourth quarters of 2015, respectively. Offshore adjusted earnings also reflected the absence of earnings from the disposal of non-core assets which was finalized in March 2014, partially offset by cost savings achieved from the Company's decision not to renew windstorm insurance coverage effective May 2013.

Adjusted earnings from Other for the nine months ended September 30, 2014 decreased slightly compared with the comparative 2013 period and reflected higher depreciation expense and financing costs from the Montana-Alberta Tie-Line, as well as higher business development costs not eligible for capitalization within Other. Partially offsetting the decrease in earnings were an increase in fees earned from the Company's Canadian midstream assets, being the Cabin Gas Plant and Pipestone and Sexsmith, and the positive impact of new wind farms placed into service over the past two years.

Adjusted earnings from Other for the third quarter of 2014 decreased compared with the corresponding 2013 period and largely reflected the same year-to-date trends; however, the Company had lower adjusted earnings from its wind farms in the third quarter of 2014.

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

- Energy Services earnings for each period reflected changes in unrealized fair value gains related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.
- Energy Services adjusted earnings for 2014 excluded a realized loss of $71 million incurred during the second quarter of 2014 to close out certain forward derivative financial contracts intended to hedge the value of committed physical transportation capacity in certain markets accessed by Energy Services, but determined to be no longer effective in doing so.
- Energy Services adjusted earnings for 2013 excluded a realized loss of $58 million incurred to close out certain forward derivative contracts intended to hedge forecasted Energy Services transactions which did not occur.
- Offshore earnings/(loss) for 2014 included an unrealized fair value loss on derivative financial instruments.
- Offshore earnings for 2014 included a gain from the disposal of non-core assets.
- Other earnings/(loss) for each period reflected changes in unrealized fair value losses on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from Blackspring Ridge.

SPONSORED INVESTMENTS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Energy Partners, L.P. (EEP)	**62**	46	**157**	119
Enbridge Energy, Limited Partnership (EELP)	**38**	8	**58**	24
Enbridge Income Fund (the Fund)	**26**	32	**91**	81
Adjusted earnings	**126**	86	**306**	224
EEP - changes in unrealized derivative fair value loss	**(6)**	(6)	**(9)**	(3)
EEP - make-up rights adjustment	**-**	-	**(1)**	-
EEP - leak remediation costs	**(12)**	(5)	**(17)**	(35)
EEP - leak insurance recoveries	**-**	-	**-**	6
EEP - tax rate differences/changes	**-**	-	**-**	(3)
The Fund - changes in unrealized derivative fair value gains	**3**	-	**3**	-
The Fund - make-up rights adjustment	**(1)**	-	**(1)**	-
The Fund - drop down transaction costs	**(2)**	-	**(2)**	-
Earnings attributable to common shareholders	**108**	75	**279**	189

EEP adjusted earnings increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings increased in EEP's liquids business primarily as a result of new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on EEP's major liquids pipelines. New assets placed into service include the replacement and expansion of Line 6B as part of Enbridge and EEP's Eastern Access initiative, as well as the Line 6B 75-mile replacement program. Within EEP's North Dakota system, the Bakken Expansion and Access programs, which enhance crude oil gathering capabilities in the Bakken region, have also been a significant contributor to adjusted earnings growth. Positive factors experienced by Canadian Mainline as noted earlier also resulted in higher throughput on EEP's Lakehead System. Partially offsetting the increase in adjusted earnings in EEP's liquids business were incremental power costs associated with higher throughput, higher depreciation expense from an increased asset base and higher operating and administrative costs primarily associated with workforce and property taxes, although for the three months ended September 30, 2014 these increases in operating and administrative costs were more than offset by lower pipeline integrity costs.

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 per barrel to US$2.49 per barrel.

Within EEP's natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary MEP, lower volumes had a negative impact on adjusted earnings. Finally, EEP's contribution to Enbridge's adjusted earnings for the first nine months of 2014 continued to reflect higher earnings from Enbridge's May 2013 investment in preferred units of EEP.

EELP earnings reflect Enbridge's interest in the United States segment of Alberta Clipper, as well as interests in both the Eastern Access and Lakehead System Mainline expansion projects. Earnings from EELP increased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods and reflected the positive contributions from assets recently placed into service, in particular the expansion of Line 6B from 240,000 bpd to 500,000 bpd completed in phases during 2014.

Adjusted earnings for the Fund for the nine months ended September 30, 2014 were higher compared with the comparative 2013 period. Higher adjusted earnings reflected strong performance from the Fund's liquids business. Also contributing to period-over-period growth in adjusted earnings was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013. Partially offsetting the adjusted earnings increase was higher income taxes.

Earnings from the Fund decreased in the third quarter of 2014 compared with the comparative 2013 period. Lower earnings were primarily attributable to higher income taxes as noted above, as well as lower earnings from the Fund's Sarnia Solar Project. Partially offsetting the decrease were positive earnings from the Fund's liquids business.

Sponsored Investments earnings were impacted by the following adjusting items:

- Earnings from EEP for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- Earnings from EEP for 2014 included a make-up rights adjustment.
- Earnings from EEP for 2014 and 2013 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*
- Earnings from EEP for 2013 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*

- Earnings from EEP for 2013 included an out-of-period, non-cash deferred income tax adjustment related to a tax law change.
- Earnings from the Fund for 2014 included an unrealized fair value gain on derivative financial instruments.
- Earnings from the Fund for 2014 included a make-up rights adjustment.
- Earnings from the Fund for 2014 included costs incurred in relation to a proposed transaction to transfer natural gas and diluent pipeline interests to the Fund. See *Recent Developments – Sponsored Investments – Enbridge Income Fund – Proposed Natural Gas and Diluent Interests Transfer.*

CORPORATE

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Noverco	**(3)**	(2)	**22**	34
Other Corporate	**(10)**	(18)	**(37)**	(46)
Adjusted loss	**(13)**	(20)	**(15)**	(12)
Noverco - changes in unrealized derivative fair value gains/(loss)	**-**	5	**(5)**	4
Other Corporate - changes in unrealized derivative fair value gains/(loss)	**(221)**	77	**(227)**	(177)
Other Corporate - gain on sale of investment	**-**	-	**14**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	4
Other Corporate - impact of tax rate changes	**-**	-	**-**	18
Earnings/(loss) attributable to common shareholders	**(234)**	62	**(233)**	(163)

Noverco adjusted earnings decreased for the nine months ended September 30, 2014 compared with the corresponding 2013 period. Noverco adjusted earnings included returns on the Company's preferred share investment as well as its equity earnings from Noverco's underlying gas and power distribution investments. Excluding the impact of a small one-time gain on sale of an investment in the first quarter of 2013 and an equity earnings true-up adjustment recognized in the first quarter of 2013, Noverco adjusted earnings were comparable between periods.

Other Corporate adjusted loss decreased for the three and nine months ended September 30, 2014 compared with the corresponding 2013 periods. The decreased loss reflected lower net corporate segment finance costs and lower income taxes partially offset by higher preference share dividends due to an increase in the number of preference shares outstanding

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

- Noverco earnings/(loss) for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- Other Corporate earnings/(loss) for each period included changes in the unrealized fair value gains and losses on derivative financial instruments primarily related to forward foreign exchange risk management positions.
- Other Corporate loss for 2014 included a gain on sale of an investment.
- Other Corporate loss for 2013 was reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate loss for 2013 was impacted by tax rate differences.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the record level of capital projects secured or under development. The Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends.

The Company's longer-term financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles through which it can monetize assets, with the objective of diversifying funding sources and maintaining access to low cost capital. In September 2014, Enbridge entered into a proposed transaction with the Fund to transfer natural gas and diluent pipeline interests to the Fund. Subject to receipt of customary regulatory approvals, the transaction is expected to provide approximately $1.2 billion of net funding to Enbridge. See *Recent Developments – Sponsored Investments – Enbridge Income Fund – Proposed Natural Gas and Diluent Interests Transfer.*

In June 2014, the Company took a significant action to re-establish EEP as a cost-effective sponsored vehicle by restructuring EEP's equity. The Equity Restructuring is expected to benefit Enbridge in the longer term by improving EEP's cost of capital and growth outlook, thus increasing the incentive distributions to Enbridge. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Sponsored Vehicle Transactions – Equity Restructuring*. Following the Equity Restructuring, Enbridge and EEP announced in September 2014 a proposed drop down of Enbridge's current 66.7% interest in the United States segment of the Alberta Clipper pipeline to EEP for proceeds of approximately US$900 million. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Sponsored Vehicle Transactions – Proposed Alberta Clipper Drop Down.*

In accordance with its funding plan, the Company has completed the following issuances to date in 2014:

- Corporate - $460 million of common shares; $1,400 million of preference shares; $1,530 million of medium-term notes; $1,641 million of senior notes;
- Liquids Pipelines - Southern Lights Pipeline - $352 million and US$1,061 million of private placement notes;
- Gas Distribution - EGD - $730 million of medium-term notes; and
- Sponsored Investments - MEP - US$400 million of private senior notes.

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge also bolstered its committed bank credit facilities in 2014. The following table provides details of the Company's committed credit facilities at September 30, 2014 and December 31, 2013.

		September 30, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**261**	**39**	300
Gas Distribution	2016-2019	**1,008**	**981**	**27**	713
Sponsored Investments	2016-2018	**4,395**	**1,861**	**2,534**	4,781
Corporate	2015-2019	**12,557**	**4,403**	**8,154**	11,805
		18,260	**7,506**	**10,754**	17,599
Southern Lights project financing[2]	2016	**27**	**-**	**27**	1,570
Total committed credit facilities		**18,287**	**7,506**	**10,781**	19,169

1 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
2 *On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million with the proceeds utilized to repay the construction credit facilities on a dollar-for-dollar basis.*

In addition to the committed credit facilities noted above, the Company also has $352 million of uncommitted demand credit facilities, of which $332 million was unutilized, as at September 30, 2014.

Subsequent to September 30, 2014, the Company has extended the maturity dates of a number of credit facilities representing total commitments of approximately of $4.4 billion for another year.

Excluding project financing, the Company's net available liquidity of $11,472 million at September 30, 2014 was inclusive of $1,088 million of unrestricted cash and cash equivalents and net of bank indebtedness of $370 million.

There are no material restrictions on the Company's cash with the exception of restricted cash of $5 million related to Southern Lights project financing and cash in trust of $34 million for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

OPERATING ACTIVITIES

Cash provided by operating activities for the three and nine months ended September 30, 2014 was $746 million and $1,891 million, respectively, compared with $830 million and $2,560 million for the three and nine months ended September 30, 2013. As discussed in *Financial Results*, the Company experienced higher earnings mainly from higher throughput and new assets placed into service within Liquids Pipelines and stronger contributions from EEP and EELP, partially offset by less favourable arbitrage opportunities in Energy Services. Also partially offsetting the increases were payments for environmental liabilities in respect to Line 6B leak, as well as lower distributions from the Company's equity investments. The Company received a one-time dividend of $248 million from its equity investment in Noverco during the second quarter of 2013.

Despite the positive earnings effects noted above, the comparability of period-over-period cash flows from operating activities was impacted by changes in operating assets and liabilities as they absorbed cash of $295 million and $1,271 million for the three and nine months ended September 30, 2014, respectively compared with a cash generation of $50 million and cash absorption of $362 million in the corresponding 2013 periods. Operating assets and liabilities fluctuate from time to time due to inventory levels, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company's businesses.

At September 30, 2014, the Company had a negative working capital position. Despite this negative working capital, the Company continues to have significant liquidity available through committed credit facilities, which allow the funding of liabilities as they become due. As at September 30, 2014, the Company's net available liquidity totalled $11,472 million (December 31, 2013 - $12,909 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

INVESTING ACTIVITIES

Cash used in investing activities for the three and nine months ended September 30, 2014 was $2,525 million and $8,154 million, respectively, compared with $2,562 million and $6,154 million for the three and nine months ended September 30, 2013. Cash used in investing activities on a period-over-period basis has primarily been impacted by additions to property, plant and equipment associated with the Company's growth projects which are further described in *Growth Projects – Commercially Secured Projects*. Additional funding of various investments and joint ventures, primarily the Seaway Pipeline Twinning/Extension project, also contributed to the increased cash usage for the nine month period ended September 30, 2014, although such funding was lower in the third quarter of 2014 compared with the third quarter of 2013.

FINANCING ACTIVITIES
For the three and nine months ended September 30, 2014, cash generated from financing activities was $1,594 million and $6,549 million, respectively, compared with $1,175 million and $2,326 million for the three and nine months ended September 30, 2013. The Company continues to execute its funding and liquidity strategy in support of its long-term growth plan. During the first nine months of 2014, the Company increased its overall debt by $5,740 million compared with an increase of $944 million during the same period in 2013. The most significant contributor of this increase during the first nine months of 2014 was the issuance of $4,334 million (2013 - $1,232 million) in medium-term and senior notes. The Company also issued preference and common shares during the same period of 2014 for net proceeds of $1,365 million and $470 million, respectively, compared with $1,186 million and $616 million for the comparative periods in 2013. Furthermore, the Company bolstered its liquidity during the first nine months of 2014 through the securement of additional credit facilities.

Additional preference and common shares outstanding gave rise to an increase in the dividends paid during the first nine months of 2014 compared with the same period of 2013, partially offsetting the cash inflows from financing activities. Also partially offsetting the cash flows from financing activities were the transactions between the Company's sponsored vehicles and their public unitholders. During the first nine months of 2014, EEP, MEP and the Fund made distributions, net of contributions, of $287 million to their public unitholders. For the comparative period in 2013, sponsored vehicles received contributions, net of distributions, of $212 million primarily as a result of their equity issuances to the public.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended September 30, 2014, dividends declared were $296 million (2013 - $261 million), of which $193 million (2013 - $167 million) were paid in cash and reflected in financing activities. The remaining $103 million (2013 - $94 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the nine months ended September 30, 2014, dividends declared were $880 million (2013 - $774 million), of which $565 million (2013 - $504 million) were paid in cash and reflected in financing activities. The remaining $315 million (2013 - $270 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and nine months ended September 30, 2014, 34.8% (2013 - 36.0%) and 35.8% (2013 - 34.9%) of total dividends declared were reinvested.

On October 22, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2014 to shareholders of record on November 14, 2014.

Common Shares	$0.35000
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[1]	$0.41290
Preference Shares, Series 15[2]	$0.20790

1 *This first dividend declared for the Preference Shares, Series 13 includes accrued dividends from July 17, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015. See* Recent Developments – Corporate – Preference Share Issuance – Series 13.

2 *The first dividend declared for the Preference Shares, Series 15 includes accrued dividends from September 23, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on March 1, 2015.* See Recent Developments – Corporate – Preference Share Issuance – Series 15.

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $3,399 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company generates certain revenues, incurs expenses and holds a number of investments and subsidiaries denominated in currencies other than Canadian dollars. As a result, the Company's earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018 through execution of floating to fixed interest rate swaps with an average swap rate of 4%.

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

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

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

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**22**	(18)	**(9)**	29
Interest rate contracts	**(173)**	(86)	**(694)**	703
Commodity contracts	**9**	(23)	**(8)**	(6)
Other contracts	**7**	(3)	**15**	(4)
Net investment hedges				
Foreign exchange contracts	**(63)**	25	**(66)**	(42)
	(198)	(105)	**(762)**	680
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(5)**	(2)	**10**	(5)
Interest rate contracts[2]	**30**	43	**74**	89
Commodity contracts[3]	**2**	5	**14**	1
Other contracts[4]	**(5)**	-	**(12)**	-
	22	46	**86**	85
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**130**	1	**158**	24
Commodity contracts[3]	**-**	-	**3**	(2)
	130	1	**161**	22
Amount of gains/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**(568)**	319	**(510)**	(382)
Interest rate contracts[2]	**1**	(2)	**3**	(7)
Commodity contracts[3]	**146**	20	**447**	124
Other contracts[4]	**5**	(1)	**12**	3
	(416)	336	**(48)**	(262)

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.
2 Reported as an (increase)/decrease to Interest expense in the Consolidated Statements of Earnings.
3 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at September 30, 2014. As a result, all credit facilities are available to the

Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances.

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

FAIR VALUE MEASUREMENTS

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

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Subsequently, the NEB issued revised "base case assumptions" based on feedback from member companies. Companies were given the option to follow the base case assumptions or to submit pipeline specific applications. On November 29, 2011, as required by the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc., Vector Pipelines Limited Partnership, Niagara Gas Transmission Limited and 2103914 Canada Limited (Group 2 companies).

In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies and issued its decision on February 14, 2013. The outcome does not materially impact tolls. On February 28, 2013, Group 1 companies filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the qualified environmental trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies filed collection mechanism applications and the Group 2 companies filed both their set-aside and collection mechanism applications. Once the set-aside and collection mechanism is approved by the NEB, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The collections are expected to begin in 2015.

All applications by the Company will require NEB approval. The NEB hearings commenced January 14, 2014, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. The NEB released its decision on May 29, 2014 approving both the set aside mechanism and collection mechanisms for all of the Enbridge Group 1 companies and Group 2 companies.

Currently, for the majority of the Company's assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2014, the Company recognized ARO in the amount of $167 million. Of this amount, $64 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur into 2015 and $103 million related to the Canadian and United States portions of the L3R Program announced in March 2014.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent's Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the interim consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

QUARTERLY FINANCIAL INFORMATION

	2014			2013				2012
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
(millions of Canadian dollars, except per share amounts)								
Revenues	**8,297**	10,026	10,521	8,293	8,998	7,730	7,897	7,007
Earnings attributable to common shareholders	**(80)**	756	390	(267)	421	42	250	146
Earnings per common share	**(0.10)**	0.92	0.48	(0.33)	0.52	0.05	0.32	0.19
Diluted earnings per common share	**(0.10)**	0.91	0.47	(0.32)	0.51	0.05	0.31	0.18
Dividends per common share	**0.3500**	0.3500	0.3500	0.3150	0.3150	0.3150	0.3150	0.2825
EGD - warmer/(colder) than normal weather	**2**	(4)	(33)	(13)	-	(2)	6	(1)
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**396**	(430)	190	613	(223)	246	207	81

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, changes in unrealized fair value gains and losses on these instruments will impact earnings.

In addition to the impacts of weather in EGD's franchise area and changes in unrealized gains and losses outlined above, significant items that impacted the quarterly earnings included:

- First quarter earnings for 2014 included a $43 million after-tax gain on the disposal of non-core Offshore assets and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.
- Included in earnings are after-tax costs of $4 million in the third quarter of 2014 as well as $40 million, $13 million and $3 million incurred respectively in the second, third and fourth quarters of 2013, in connection with the Line 37 crude oil release which occurred in June 2013. Earnings also reflected

insurance recoveries associated with the Line 37 crude oil release of $4 million recognized in the second quarter of 2014.

- Reflected in earnings is the Company's share of leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $5 million and $12 million were recognized in the second and third quarters of 2014; and $24 million, $6 million, $5 million and $9 million were recognized in the first, second, third and fourth quarters of 2013. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013.
- Fourth quarter earnings for 2012 included a $63 million, after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.
- Fourth quarter earnings for 2012 included an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors.
- Fourth quarter earnings for 2012 also included the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million incurred on the related capital gain.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development.*

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Earnings/(loss) attributable to common shareholders	**(80)**	421	**1,066**	713
Adjusting items:				
Liquids Pipelines				
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**231**	(133)	**192**	125
Canadian Mainline - Line 9B costs incurred during reversal	**2**	-	**6**	-
Regional Oil Sands System - make-up rights adjustment	**(5)**	-	**(5)**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	37	**-**	37
Regional Oil Sands System - leak insurance recoveries	**-**	-	**(4)**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**4**	13	**4**	53
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	(31)	**-**	(31)
Southern Lights Pipeline - changes in unrealized derivative fair value loss[1]	**9**	-	**9**	-
Seaway Pipeline - make-up rights adjustment	**11**	-	**11**	-
Spearhead Pipeline - make-up rights adjustment	**-**	-	**1**	-
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	-	**(3)**	-
Feeder Pipelines and Other - project development costs	**1**	-	**4**	-
Gas Distribution				
EGD - warmer/(colder) than normal weather	**2**	-	**(35)**	4
EGD - gas transportation cost cut-off-period adjustment	**-**	56	**-**	56
Gas Pipelines, Processing and Energy Services				
Energy Services - changes in unrealized derivative fair value gains[1]	**(71)**	(18)	**(288)**	(131)
Offshore - changes in unrealized derivative fair value loss[1]	**2**	-	**2**	-
Offshore - gain on sale of non-core assets	**-**	-	**(43)**	-
Other - changes in unrealized derivative fair value loss[1]	**1**	4	**3**	60
Sponsored Investments				
EEP - changes in unrealized derivative fair value loss[1]	**6**	6	**9**	3
EEP - make-up rights adjustment	**-**	-	**1**	-
EEP - leak remediation costs	**12**	5	**17**	35
EEP - leak insurance recoveries	**-**	-	**-**	(6)
EEP - tax rate differences/changes	**-**	-	**-**	3
The Fund - changes in unrealized derivative fair value gains[1]	**(3)**	-	**(3)**	-
The Fund - make-up rights adjustment	**1**	-	**1**	-
The Fund - drop down transaction costs	**2**	-	**2**	-
Corporate				
Noverco - changes in unrealized derivative fair value (gains)/loss[1]	**-**	(5)	**5**	(4)
Other Corporate - changes in unrealized derivative fair value (gains)/loss[1]	**221**	(77)	**227**	177
Other Corporate - gain on sale of investment	**-**	-	**(14)**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	(4)
Other Corporate - impact of tax rate changes	**-**	-	**-**	(18)
Adjusted earnings	**345**	278	**1,165**	1,072

1 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.

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

	Number	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	20,000,000	June 1, 2017	Series C
Preference Shares, Series D	18,000,000	March 1, 2018	Series E
Preference Shares, Series F	20,000,000	June 1, 2018	Series G
Preference Shares, Series H	14,000,000	September 1, 2018	Series I
Preference Shares, Series J	8,000,000	June 1, 2017	Series K
Preference Shares, Series L	16,000,000	September 1, 2017	Series M
Preference Shares, Series N	18,000,000	December 1, 2018	Series O
Preference Shares, Series P	16,000,000	March 1, 2019	Series Q
Preference Shares, Series R	16,000,000	June 1, 2019	Series S
Preference Shares, Series 1	16,000,000	June 1, 2018	Series 2
Preference Shares, Series 3	24,000,000	September 1, 2019	Series 4
Preference Shares, Series 5	8,000,000	March 1, 2019	Series 6
Preference Shares, Series 7	10,000,000	March 1, 2019	Series 8
Preference Shares, Series 9	11,000,000	December 1, 2019	Series 10
Preference Shares, Series 11	20,000,000	March 1, 2020	Series 12
Preference Shares, Series 13	14,000,000	June 1, 2020	Series 14
Preference Shares, Series 15	11,000,000	September 1, 2020	Series 16

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	848,768,217
Stock Options - issued and outstanding (19,448,722 vested)	36,787,816

1 *Outstanding share data information is provided as at October 24, 2014.*

2 *All preference shares are non-voting equity shares. Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, the Company may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.*

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

September 30, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**6,599**	7,141	**22,089**	19,100
Gas distribution sales	**309**	270	**2,018**	1,555
Transportation and other services	**1,389**	1,587	**4,737**	3,970
	8,297	8,998	**28,844**	24,625
Expenses				
Commodity costs	**6,459**	6,981	**21,578**	18,449
Gas distribution costs	**149**	217	**1,332**	1,095
Operating and administrative	**805**	766	**2,364**	2,226
Depreciation and amortization	**392**	352	**1,151**	1,008
Environmental costs, net of recoveries *(Note 15)*	**62**	41	**103**	280
	7,867	8,357	**26,528**	23,058
	430	641	**2,316**	1,567
Income from equity investments	**72**	79	**251**	244
Other income/(expense)	**(220)**	164	**(143)**	(53)
Interest expense	**(347)**	(223)	**(816)**	(682)
	(65)	661	**1,608**	1,076
Income taxes recovery/(expense) *(Note 13)*	**31**	(236)	**(362)**	(339)
Earnings/(loss) from continuing operations	**(34)**	425	**1,246**	737
Discontinued operations *(Note 4)*				
Earnings from discontinued operations before income taxes	**-**	-	**73**	-
Income taxes from discontinued operations	**-**	-	**(27)**	-
Earnings from discontinued operations	**-**	-	**46**	-
Earnings/(loss)	**(34)**	425	**1,292**	737
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	45	**(46)**	107
Earnings/(loss) attributable to Enbridge Inc.	**(14)**	470	**1,246**	844
Preference share dividends	**(66)**	(49)	**(180)**	(131)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**(80)**	421	**1,066**	713
Earnings/(loss) attributable to Enbridge Inc. common shareholders				
Earnings/(loss) from continuing operations	**(80)**	421	**1,020**	713
Earnings from discontinued operations, net of tax	**-**	-	**46**	-
	(80)	421	**1,066**	713
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 9)*				
Continuing operations	**(0.10)**	0.52	**1.23**	0.89
Discontinued operations	**-**	-	**0.06**	-
	(0.10)	0.52	**1.29**	0.89
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 9)*				
Continuing operations	**(0.10)**	0.51	**1.21**	0.88
Discontinued operations	**-**	-	**0.06**	-
	(0.10)	0.51	**1.27**	0.88

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars)				
Earnings/(loss)	**(34)**	425	**1,292**	737
Other comprehensive income/(loss), net of tax				
Change in unrealized gains/(loss) on cash flow hedges	**(96)**	(44)	**(610)**	540
Change in unrealized gains/(loss) on net investment hedges	**(143)**	34	**(134)**	(40)
Other comprehensive income/(loss) from equity investees	**(3)**	6	**4**	12
Reclassification to earnings of realized cash flow hedges	**(13)**	31	**62**	66
Reclassification to earnings of unrealized cash flow hedges	**100**	2	**124**	17
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**3**	5	**6**	22
Change in foreign currency translation adjustment	**671**	(241)	**687**	288
Other comprehensive income/(loss)	**519**	(207)	**139**	905
Comprehensive income	**485**	218	**1,431**	1,642
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(94)**	122	**(67)**	(134)
Comprehensive income attributable to Enbridge Inc.	**391**	340	**1,364**	1,508
Preference share dividends	**(66)**	(49)	**(180)**	(131)
Comprehensive income attributable to Enbridge Inc. common shareholders	**325**	291	**1,184**	1,377

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Nine months ended September 30,	
	2014	2013
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 9)*		
Balance at beginning of period	**5,141**	3,707
Preference shares issued	**1,374**	1,189
Balance at end of period	**6,515**	4,896
Common shares		
Balance at beginning of period	**5,744**	4,732
Shares issued	**446**	586
Dividend reinvestment and share purchase plan	**315**	270
Shares issued on exercise of stock options	**40**	54
Balance at end of period	**6,545**	5,642
Additional paid-in capital		
Balance at beginning of period	**746**	522
Stock-based compensation	**25**	24
Options exercised	**(11)**	(14)
Issuance of treasury stock	**22**	208
Enbridge Energy Partners, L.P. equity restructuring *(Note 10)*	**1,584**	-
Drop down of interest to Midcoast Energy Partners, L.P.	**(18)**	-
Dilution gains and other	**5**	4
Balance at end of period	**2,353**	744
Retained earnings		
Balance at beginning of period	**2,550**	3,173
Earnings attributable to Enbridge Inc.	**1,246**	844
Preference share dividends	**(180)**	(131)
Common share dividends declared	**(880)**	(774)
Dividends paid to reciprocal shareholder	**13**	15
Redemption value adjustment attributable to redeemable noncontrolling interests	**(364)**	(32)
Balance at end of period	**2,385**	3,095
Accumulated other comprehensive loss *(Note 11)*		
Balance at beginning of period	**(599)**	(1,762)
Other comprehensive income attributable to Enbridge Inc. common shareholders	**118**	664
Balance at end of period	**(481)**	(1,098)
Reciprocal shareholding		
Balance at beginning of period	**(86)**	(126)
Issuance of treasury stock	**3**	40
Balance at end of period	**(83)**	(86)
Total Enbridge Inc. shareholders' equity	**17,234**	13,193
Noncontrolling interests		
Balance at beginning of period	**4,014**	3,258
Earnings/(loss) attributable to noncontrolling interests	**46**	(87)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**(144)**	131
Change in foreign currency translation adjustment	**95**	105
Reclassification to earnings of realized cash flow hedges	**21**	3
Reclassification to earnings of unrealized cash flow hedges	**58**	(1)
	30	238
Comprehensive income attributable to noncontrolling interests	**76**	151
Contributions	**163**	523
Distributions	**(395)**	(348)
Enbridge Energy Partners, L.P. equity restructuring *(Note 10)*	**(2,330)**	-
Drop down of interest to Midcoast Energy Partners, L.P.	**39**	-
Other	**2**	1
Balance at end of period	**1,569**	3,585
Total equity	**18,803**	16,778
Dividends paid per common share	**1.050**	0.945

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings/(loss)	**(34)**	425	**1,292**	737
Earnings from discontinued operations	**-**	-	**(46)**	-
Depreciation and amortization	**392**	352	**1,151**	1,008
Deferred income taxes (recovery)/expense	**(14)**	294	**332**	365
Changes in unrealized (gains)/loss on derivative instruments, net	**419**	(332)	**56**	274
Cash distributions in excess of equity earnings	**90**	105	**139**	316
Gain on disposition	**-**	-	**(16)**	-
Hedge ineffectiveness *(Note 12)*	**130**	1	**161**	22
Other	**73**	(59)	**110**	(15)
Changes in regulatory assets and liabilities	**(4)**	(6)	**11**	14
Changes in environmental liabilities, net of recoveries *(Note 15)*	**(11)**	-	**(47)**	201
Changes in operating assets and liabilities	**(295)**	50	**(1,271)**	(362)
Cash provided by continuing operations	**746**	830	**1,872**	2,560
Cash provided by discontinued operations *(Note 4)*	**-**	-	**19**	-
	746	830	**1,891**	2,560
Investing activities				
Additions to property, plant and equipment	**(2,354)**	(2,229)	**(7,397)**	(5,285)
Long-term investments	**(168)**	(303)	**(693)**	(726)
Additions to intangible assets	**(42)**	(26)	**(153)**	(137)
Proceeds from disposition	**62**	-	**81**	-
Affiliate loans, net	**3**	2	**9**	5
Changes in restricted cash	**(26)**	(6)	**(5)**	(11)
Cash used in continuing operations	**(2,525)**	(2,562)	**(8,158)**	(6,154)
Cash provided by discontinued operations *(Note 4)*	**-**	-	**4**	-
	(2,525)	(2,562)	**(8,154)**	(6,154)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**191**	(371)	**635**	(225)
Net change in commercial paper and credit facility draws	**381**	223	**1,596**	352
Southern Lights credit facility repayments	**(1,507)**	-	**(1,507)**	(5)
Debenture and term note issues - Southern Lights	**1,507**	-	**1,507**	-
Debenture and term note issues	**878**	1,232	**4,334**	1,232
Debenture and term note repayments	**(200)**	-	**(825)**	(410)
Contributions from noncontrolling interests	**82**	243	**163**	523
Distributions to noncontrolling interests	**(135)**	(120)	**(395)**	(348)
Contributions from redeemable noncontrolling interests	**-**	-	**-**	91
Distributions to redeemable noncontrolling interests	**(18)**	(18)	**(55)**	(54)
Preference shares issued	**607**	200	**1,365**	1,186
Common shares issued	**64**	2	**470**	616
Preference share dividends	**(63)**	(49)	**(174)**	(128)
Common share dividends	**(193)**	(167)	**(565)**	(504)
	1,594	1,175	**6,549**	2,326
Effect of translation of foreign denominated cash and cash equivalents	**25**	(4)	**26**	8
Increase/(decrease) in cash and cash equivalents	**(160)**	(561)	**312**	(1,260)
Cash and cash equivalents at beginning of period - discontinued operations	**-**	-	**20**	-
Cash and cash equivalents at beginning of period - continuing operations	**1,248**	1,077	**756**	1,776
Cash and cash equivalents at end of period	**1,088**	516	**1,088**	516

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited; millions of Canadian dollars; number of shares in millions)	**September 30, 2014**	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	**1,088**	756
Restricted cash	**39**	34
Accounts receivable and other *(Note 5)*	**4,569**	4,956
Accounts receivable from affiliates	**161**	65
Inventory	**1,458**	1,115
Assets held for sale *(Note 4)*	**-**	24
	7,315	6,950
Property, plant and equipment, net	**49,819**	42,279
Long-term investments *(Note 6)*	**5,150**	4,212
Deferred amounts and other assets	**2,992**	2,662
Intangible assets, net	**1,111**	1,004
Goodwill	**468**	445
Deferred income taxes	**230**	16
	67,085	57,568
Liabilities and equity		
Current liabilities		
Bank indebtedness	**370**	338
Short-term borrowings	**977**	374
Accounts payable and other	**6,225**	6,664
Accounts payable to affiliates	**39**	46
Interest payable	**289**	228
Environmental liabilities	**183**	260
Current maturities of long-term debt *(Note 7)*	**1,481**	2,811
Liabilities held for sale *(Note 4)*	**-**	7
	9,564	10,728
Long-term debt *(Note 7)*	**29,354**	22,357
Other long-term liabilities	**3,613**	2,938
Deferred income taxes	**4,398**	2,925
Liabilities held for sale *(Note 4)*	**-**	57
	46,929	39,005
Contingencies *(Note 15)*		
Redeemable noncontrolling interests	**1,353**	1,053
Equity		
Share capital		
Preference shares *(Note 9)*	**6,515**	5,141
Common shares (849 and 831 outstanding at September 30, 2014 and December 31, 2013, respectively)	**6,545**	5,744
Additional paid-in capital	**2,353**	746
Retained earnings	**2,385**	2,550
Accumulated other comprehensive loss *(Note 11)*	**(481)**	(599)
Reciprocal shareholding	**(83)**	(86)
Total Enbridge Inc. shareholders' equity	**17,234**	13,496
Noncontrolling interests	**1,569**	4,014
	18,803	17,510
	67,085	57,568

See accompanying notes to the unaudited interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2013. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, with the exception of certain out-of-period adjustments further described in Note 3, Segmented Information, which management considers necessary to present fairly the Company's financial position as at September 30, 2014 and results of operations and cash flows for the three and nine months ended September 30, 2014 and 2013. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's consolidated financial statements as at and for the year ended December 31, 2013, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

The Company's operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility business, as well as other factors such as the supply of and demand for crude oil and natural gas.

2. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent's Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the interim consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

3. SEGMENTED INFORMATION

Three months ended September 30, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**382**	**354**	**5,355**	**2,206**	**-**	**8,297**
Commodity and gas distribution costs	**-**	**(150)**	**(5,122)**	**(1,336)**	**-**	**(6,608)**
Operating and administrative	**(270)**	**(129)**	**(52)**	**(351)**	**(3)**	**(805)**
Depreciation and amortization	**(123)**	**(53)**	**(47)**	**(164)**	**(5)**	**(392)**
Environmental costs, net of recoveries	**(7)**	**-**	**-**	**(55)**	**-**	**(62)**
	(18)	**22**	**134**	**300**	**(8)**	**430**
Income/(loss) from equity investments	**35**	**-**	**33**	**20**	**(16)**	**72**
Other income/(expense)	**(9)**	**(5)**	**(1)**	**12**	**(217)**	**(220)**
Interest expense	**(86)**	**(43)**	**(29)**	**(176)**	**(13)**	**(347)**
Income taxes recovery/(expense)	**48**	**15**	**(49)**	**(69)**	**86**	**31**
Earnings/(loss)	**(30)**	**(11)**	**88**	**87**	**(168)**	**(34)**
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**21**	**-**	**20**
Preference share dividends	**-**	**-**	**-**	**-**	**(66)**	**(66)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**(31)**	**(11)**	**88**	**108**	**(234)**	**(80)**
Additions to property, plant and equipment[2]	**1,287**	**99**	**134**	**817**	**18**	**2,355**

Three months ended September 30, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	913	339	5,826	1,920	-	8,998
Commodity and gas distribution costs	-	(217)	(5,698)	(1,283)	-	(7,198)
Operating and administrative	(236)	(131)	(43)	(353)	(3)	(766)
Depreciation and amortization	(112)	(79)	(21)	(136)	(4)	(352)
Environmental costs, net of recoveries	(17)	-	-	(24)	-	(41)
	548	(88)	64	124	(7)	641
Income/(loss) from equity investments	28	-	45	14	(8)	79
Other income	9	10	12	6	127	164
Interest income/(expense)	(90)	(40)	(20)	(94)	21	(223)
Income taxes recovery/(expense)	(193)	33	(33)	(21)	(22)	(236)
Earnings/(loss)	302	(85)	68	29	111	425
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	46	-	45
Preference share dividends	-	-	-	-	(49)	(49)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	301	(85)	68	75	62	421
Additions to property, plant and equipment[2]	1,060	139	325	695	11	2,230

Nine months ended September 30, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**1,820**	**2,268**	**18,063**	**6,693**	**-**	**28,844**
Commodity and gas distribution costs	**-**	**(1,333)**	**(17,291)**	**(4,286)**	**-**	**(22,910)**
Operating and administrative	**(805)**	**(399)**	**(136)**	**(1,015)**	**(9)**	**(2,364)**
Depreciation and amortization	**(361)**	**(225)**	**(82)**	**(469)**	**(14)**	**(1,151)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(103)**	**-**	**(103)**
	654	**311**	**554**	**820**	**(23)**	**2,316**
Income/(loss) from equity investments	**110**	**-**	**111**	**55**	**(25)**	**251**
Other income/(expense)	**(6)**	**(3)**	**8**	**10**	**(152)**	**(143)**
Interest income/(expense)	**(260)**	**(123)**	**(72)**	**(397)**	**36**	**(816)**
Income taxes recovery/(expense)	**(51)**	**(41)**	**(215)**	**(166)**	**111**	**(362)**
Earnings/(loss) from continuing operations	**447**	**144**	**386**	**322**	**(53)**	**1,246**
Discontinued operations						
Earnings from discontinued operations before income tax	**-**	**-**	**73**	**-**	**-**	**73**
Income taxes from discontinued operations	**-**	**-**	**(27)**	**-**	**-**	**(27)**
Earnings from discontinued operations	**-**	**-**	**46**	**-**	**-**	**46**
Earnings/(loss)	**447**	**144**	**432**	**322**	**(53)**	**1,292**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(3)**	**-**	**-**	**(43)**	**-**	**(46)**
Preference share dividends	**-**	**-**	**-**	**-**	**(180)**	**(180)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**444**	**144**	**432**	**279**	**(233)**	**1,066**
Additions to property, plant and equipment[2]	**4,301**	**307**	**463**	**2,286**	**42**	**7,399**

Nine months ended September 30, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	1,780	1,900	15,484	5,461	-	24,625
Commodity and gas distribution costs	-	(1,095)	(14,895)	(3,554)	-	(19,544)
Operating and administrative	(726)	(400)	(204)	(895)	(1)	(2,226)
Depreciation and amortization	(315)	(237)	(52)	(391)	(13)	(1,008)
Environmental costs, net of recoveries	(68)	-	-	(212)	-	(280)
	671	168	333	409	(14)	1,567
Income from equity investments	89	-	109	41	5	244
Other income/(expense)	29	12	32	10	(136)	(53)
Interest income/(expense)	(234)	(118)	(58)	(285)	13	(682)
Income taxes recovery/(expense)	(171)	(13)	(159)	(96)	100	(339)
Earnings/(loss)	384	49	257	79	(32)	737
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	-	-	110	-	107
Preference share dividends	-	-	-	-	(131)	(131)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	381	49	257	189	(163)	713
Additions to property, plant and equipment[2]	2,690	360	591	1,625	20	5,286

1 *Included within the Corporate segment was Interest income of $182 million and $498 million for the three and nine months ended September 30, 2014, respectively, (2013 - $121 million and $314 million, respectively) charged to other operating segments.*

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

OUT-OF-PERIOD ADJUSTMENTS

For the three months ended September 30, 2014, Commodity sales revenues and Commodity costs were increased by a non-cash out-of-period adjustment of $174 million. The adjustment relates to understatement of Commodity sales revenues and Commodity costs for the first half of 2014 and has no impact on earnings.

Earnings attributable to Enbridge Inc. common shareholders for the three months ended September 30, 2013 were reduced by out-of-period adjustments of $77 million. The adjustment attributable to the Liquids Pipelines segment was a net decrease to earnings of $6 million. Of this net adjustment, $37 million related to a non-cash adjustment to defer revenues associated with make-up rights created pursuant to certain take-or-pay contracts that had more than a remote chance of being utilized. The Liquids Pipelines adjustment also included a net increase to earnings of $31 million related to the recovery of income taxes under a long-term contract, partially offset by a correction to deferred income tax expense. The adjustment attributable to the Gas Distribution segment was $71 million and represented an increase to gas transportation costs which had incorrectly been deferred. These out-of-period adjustments for the three months ended September 30, 2013 increased Transportation and other services revenues, Gas distribution costs, and Income taxes by $102 million, $98 million and $83 million, respectively.

TOTAL ASSETS

	September 30, 2014	December 31, 2013
(millions of Canadian dollars)		
Liquids Pipelines	**26,093**	20,950
Gas Distribution	**8,872**	7,942
Gas Pipelines, Processing and Energy Services	**6,860**	7,015
Sponsored Investments	**21,541**	18,527
Corporate	**3,719**	3,134
	67,085	57,568

4. DISCONTINUED OPERATIONS

Effective March 1, 2014, the Company completed the sale of certain of its Enbridge Offshore Pipelines assets located within the Stingray corridor to an unrelated third party for cash proceeds of $11 million (US$10 million), subject to working capital adjustments. The gain of $70 million (US$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of $59 million (US$53 million), is presented as Earnings from discontinued operations. The results of operations, including revenues of $4 million and related cash flows, have also been presented as discontinued operations for the nine months ended September 30, 2014. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain Enbridge Energy Partners, L.P. (EEP) subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$411 million ($461 million) and US$380 million ($404 million) as at September 30, 2014 and December 31, 2013, respectively.

6. LONG-TERM INVESTMENTS

Effective July 1, 2014, the Company sold a 35% equity interest in Southern Access Extension Project (the Project), a pipeline construction project, to an unrelated third party. As the fair value of the consideration received equalled carrying value of the asset sold, no gain or loss was recognized on the sale. As at December 31, 2013, the subsidiary executing the Project was wholly-owned and consolidated within the Liquids Pipelines segment. Effective July 1, 2014, the Company's remaining 65% interest in the Project is now accounted for as a long-term equity investment within the Liquids Pipelines segment.

7. DEBT

During the nine months ended September 30, 2014, the Company completed aggregate issuances of unsecured, medium-term notes of $2,260 million and senior notes of US$1,900 million. The Company also raised private debt related to project financing of $352 million and US$1,061 million.

These aggregate issuances and private debt carry interest rates ranging from 0.7% to 4.6% and have maturities ranging from three to 30 years, with the exception of $130 million in term notes that mature in 50 years.

CREDIT FACILITIES

The following table provides details of the Company's committed credit facilities at September 30, 2014 and December 31, 2013.

		September 30, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**261**	**39**	300
Gas Distribution	2016-2019	**1,008**	**981**	**27**	713
Sponsored Investments	2016-2018	**4,395**	**1,861**	**2,534**	4,781
Corporate	2015-2019	**12,557**	**4,403**	**8,154**	11,805
		18,260	**7,506**	**10,754**	17,599
Southern Lights project financing[2]	2016	**27**	**-**	**27**	1,570
Total committed credit facilities		**18,287**	**7,506**	**10,781**	19,169

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

2 *On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million with the proceeds utilized to repay the construction credit facilities on a dollar-for-dollar basis.*

In addition to the committed credit facilities noted above, the Company also has $352 million of uncommitted demand credit facilities, of which $332 million was unutilized as at September 30, 2014.

Subsequent to September 30, 2014, the Company has extended the maturity dates of a number of credit facilities representing total commitments of approximately $4.4 billion for another year.

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2015 to 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $6,275 million (December 31, 2013 - $4,580 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

8. ASSET RETIREMENT OBLIGATIONS

During the nine months ended September 30, 2014, the Company recognized asset retirement obligations (ARO) in the amount of $167 million. Of the amount, $64 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur into 2015 and $103 million related to the Canadian and United States portions of the Line 3 Replacement Program announced in March 2014.

The Company records ARO at fair value in the period in which they can be reasonably determined. Fair value is determined based on expected future cash flows and estimated retirement periods, as well as discount and inflation rates. As at September 30, 2014, ARO of $64 million were classified within

Accounts payable and other and $103 million were classified within Other long-term liabilities, with an offset to Property, plant and equipment on the Consolidated Statements of Financial Position.

9. SHARE CAPITAL

PREFERENCE SHARES

	September 30, 2014		December 31, 2013	
	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of preference shares in millions)				
Preference Shares, Series A	**5**	**125**	5	125
Preference Shares, Series B	**20**	**500**	20	500
Preference Shares, Series D	**18**	**450**	18	450
Preference Shares, Series F	**20**	**500**	20	500
Preference Shares, Series H	**14**	**350**	14	350
Preference Shares, Series J	**8**	**199**	8	199
Preference Shares, Series L	**16**	**411**	16	411
Preference Shares, Series N	**18**	**450**	18	450
Preference Shares, Series P	**16**	**400**	16	400
Preference Shares, Series R	**16**	**400**	16	400
Preference Shares, Series 1	**16**	**411**	16	411
Preference Shares, Series 3	**24**	**600**	24	600
Preference Shares, Series 5	**8**	**206**	8	206
Preference Shares, Series 7	**10**	**250**	10	250
Preference Shares, Series 9	**11**	**275**	-	-
Preference Shares, Series 11	**20**	**500**	-	-
Preference Shares, Series 13	**14**	**350**	-	-
Preference Shares, Series 15	**11**	**275**	-	-
Issuance costs		**(137)**		(111)
Balance at end of period		**6,515**		5,141

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.0%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.0%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.4%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7	4.4%	$1.100	$25	March 1, 2019	Series 8
Preference Shares, Series 9	4.4%	$1.100	$25	December 1, 2019	Series 10
Preference Shares, Series 11	4.4%	$1.100	$25	March 1, 2020	Series 12
Preference Shares, Series 13[5]	4.4%	$1.100	$25	June 1, 2020	Series 14
Preference Shares, Series 15[5]	4.4%	$1.100	$25	September 1, 2020	Series 16

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*

2 *Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, the Company may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.*

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14) or 2.7% (Series 16); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).*

5 *Cash dividends of $0.4129 per share and $0.2079 per share will be payable to Series 13 and Series 15 shareholders, respectively, on December 1, 2014. The regular quarterly dividend of $0.275 per share for each of these series takes effect on March 1, 2015.*

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2013 - 12 million and 16 million) for the three and nine months ended September 30, 2014, resulting from the Company's reciprocal investment in Noverco Inc.

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(number of shares in millions)				
Weighted average shares outstanding	**835**	814	**826**	803
Effect of dilutive options	**12**	10	**11**	11
Diluted weighted average shares outstanding	**847**	824	**837**	814

For the nine months ended September 30, 2014, 5,920,500 anti-dilutive stock options (2013 - 6,327,500) with a weighted average exercise price of $48.78 (2013 - $44.85) were excluded from the diluted earnings per common share calculation. For the three months ended September 30, 2014, there were no anti-dilutive stock options (2013 - 6,327,500 with a weighted average exercise price of $44.85).

10. ENBRIDGE ENERGY PARTNERS, L.P. EQUITY RESTRUCTURING

Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly-owned subsidiary of Enbridge and the General Partner (GP) of EEP, entered into an equity restructuring transaction in which the Company irrevocably waived its right to receive cash distributions and allocations in excess of 2% in respect of its GP interest in the existing incentive distribution rights in exchange for the issuance of (i) 66.1 million units of a new class of EEP units designated as Class D Units, and (ii) 1,000 units of a new class of EEP units designated as Incentive Distribution Units (IDU). The Class D Units entitle the Company to receive quarterly distributions equal to the distribution paid on the EEP's common units. This restructuring decreases the Company's share of incremental cash distributions from 48% of all distributions in excess of US$0.495 per unit per quarter down to 23% of all distributions in excess of EEP's current quarterly distribution of US$0.5435 per unit per quarter. The transaction applies to all distributions declared subsequent to the effective date. EEP recorded the Class D Units and IDU at fair value which resulted in a reduction to the carrying amounts of the GP and limited partner capital accounts on a pro-rata basis. As a result, the Company recorded a decrease in Noncontrolling interests of $2,363 million inclusive of CTA and increases in Additional paid-in capital and Deferred income tax liabilities of $1,584 million and $779 million, respectively.

11. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in Accumulated other comprehensive loss (AOCI) attributable to Enbridge common shareholders for the nine months ended September 30, 2014 and 2013 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	**(1)**	**378**	**(778)**	**(15)**	**(183)**	**(599)**
Other comprehensive income/(loss) retained in AOCI	**(628)**	**(155)**	**592**	**4**	**-**	**(187)**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**150**	**-**	**-**	**-**	**-**	**150**
Commodity contracts[2]	**8**	**-**	**-**	**-**	**-**	**8**
Foreign exchange contracts[3]	**10**	**-**	**-**	**-**	**-**	**10**
Other contracts[4]	**(29)**	**-**	**-**	**-**	**-**	**(29)**
Amortization of pension and OPEB actuarial loss and prior service cost[5]	**-**	**-**	**-**	**-**	**10**	**10**
	(489)	**(155)**	**592**	**4**	**10**	**(38)**
Tax impact						
Income tax on amounts retained in AOCI	**171**	**21**	**-**	**-**	**-**	**192**
Income tax on amounts reclassified to earnings	**(32)**	**-**	**-**	**-**	**(4)**	**(36)**
	139	**21**	**-**	**-**	**(4)**	**156**
Balance at September 30, 2014	**(351)**	**244**	**(186)**	**(11)**	**(177)**	**(481)**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	(621)	474	(1,265)	(26)	(324)	(1,762)
Other comprehensive income/(loss) retained in AOCI	557	(46)	183	12	-	706
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	107	-	-	-	-	107
Foreign exchange contracts[3]	(5)	-	-	-	-	(5)
Amortization of pension and OPEB actuarial loss and prior service cost[5]	-	-	-	-	29	29
	659	(46)	183	12	29	837
Tax impact						
Income tax on amounts retained in AOCI	(147)	6	-	-	-	(141)
Income tax on amounts reclassified to earnings	(25)	-	-	-	(7)	(32)
	(172)	6	-	-	(7)	(173)
Balance at September 30, 2013	(134)	434	(1,082)	(14)	(302)	(1,098)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
3 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

12. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk
The Company generates certain revenues, incurs expenses, and holds a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018 through execution of floating to fixed interest rate swaps with an average swap rate of 4%.

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

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

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The

Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges as at September 30, 2014 or December 31, 2013.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances. The following table also summarizes the maximum potential settlement in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

September 30, 2014	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**3**	**9**	**10**	**22**	**(21)**	**1**
Interest rate contracts	**14**	**-**	**4**	**18**	**(5)**	**13**
Commodity contracts	**4**	**-**	**152**	**156**	**(47)**	**109**
Other contracts	**1**	**-**	**11**	**12**	**-**	**12**
	22	**9**	**177**	**208**	**(73)**	**135**
Deferred amounts and other assets						
Foreign exchange contracts	**19**	**23**	**2**	**44**	**(42)**	**2**
Interest rate contracts	**53**	**-**	**-**	**53**	**(25)**	**28**
Commodity contracts	**2**	**-**	**31**	**33**	**(15)**	**18**
Other contracts	**5**	**-**	**5**	**10**	**-**	**10**
	79	**23**	**38**	**140**	**(82)**	**58**
Accounts payable and other						
Foreign exchange contracts	**(4)**	**(48)**	**(151)**	**(203)**	**21**	**(182)**
Interest rate contracts	**(83)**	**-**	**(5)**	**(88)**	**5**	**(83)**
Commodity contracts	**(3)**	**-**	**(218)**	**(221)**	**47**	**(174)**
	(90)	**(48)**	**(374)**	**(512)**	**73**	**(439)**
Other long-term liabilities						
Foreign exchange contracts	**-**	**(41)**	**(797)**	**(838)**	**42**	**(796)**
Interest rate contracts	**(620)**	**-**	**-**	**(620)**	**25**	**(595)**
Commodity contracts	**-**	**-**	**(517)**	**(517)**	**15**	**(502)**
	(620)	**(41)**	**(1,314)**	**(1,975)**	**82**	**(1,893)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**18**	**(57)**	**(936)**	**(975)**	**-**	**(975)**
Interest rate contracts	**(636)**	**-**	**(1)**	**(637)**	**-**	**(637)**
Commodity contracts	**3**	**-**	**(552)**	**(549)**	**-**	**(549)**
Other contracts	**6**	**-**	**16**	**22**	**-**	**22**
	(609)	**(57)**	**(1,473)**	**(2,139)**	**-**	**(2,139)**

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	16	11	51	78	(26)	52
Interest rate contracts	171	-	12	183	(27)	156
Commodity contracts	4	-	114	118	(64)	54
Other contracts	2	-	4	6	-	6
	193	11	181	385	(117)	268
Deferred amounts and other assets						
Foreign exchange contracts	7	33	27	67	(62)	5
Interest rate contracts	249	-	1	250	(47)	203
Commodity contracts	9	-	86	95	(67)	28
Other contracts	1	-	-	1	-	1
	266	33	114	413	(176)	237
Accounts payable and other						
Foreign exchange contracts	(2)	(4)	(69)	(75)	26	(49)
Interest rate contracts	(387)	-	(16)	(403)	45	(358)
Commodity contracts	(14)	-	(345)	(359)	64	(295)
	(403)	(4)	(430)	(837)	135	(702)
Other long-term liabilities						
Foreign exchange contracts	(4)	(31)	(435)	(470)	62	(408)
Interest rate contracts	(68)	-	(1)	(69)	29	(40)
Commodity contracts	(2)	-	(854)	(856)	67	(789)
	(74)	(31)	(1,290)	(1,395)	158	(1,237)
Total net derivative asset/(liability)						
Foreign exchange contracts	17	9	(426)	(400)	-	(400)
Interest rate contracts	(35)	-	(4)	(39)	-	(39)
Commodity contracts	(3)	-	(999)	(1,002)	-	(1,002)
Other contracts	3	-	4	7	-	7
	(18)	9	(1,425)	(1,434)	-	(1,434)

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

September 30, 2014	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**236**	**25**	**25**	**413**	**2**	**4**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,141**	**2,751**	**2,323**	**2,557**	**1,714**	**3,771**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**1**	**28**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**1,404**	**5,605**	**5,382**	**4,372**	**3,268**	**674**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**860**	**2,597**	**1,742**	**2,450**	**1,062**	**-**
Equity contracts *(millions of Canadian dollars)*	**35**	**41**	**51**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(49)**	**(78)**	**(45)**	**(34)**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(6)**	**(22)**	**(24)**	**(18)**	**(9)**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(16)**	**(6)**	**(3)**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**13**	**25**	**40**	**40**	**30**	**8**

December 31, 2013	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	710	25	25	413	2	4
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,795	2,751	2,323	2,557	1,649	3,771
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	5	28	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,007	5,210	5,030	3,965	274	267
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	5,736	1,779	1,814	1,090	-	-
Equity contracts *(millions of Canadian dollars)*	40	41	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	17	(8)	10	11	46	-
Commodity contracts - crude oil *(millions of barrels)*	(34)	(29)	(23)	(18)	(9)	-
Commodity contracts - NGL *(millions of barrels)*	(10)	(2)	-	-	-	-
Commodity contracts - power *(MWH)*	55	5	20	40	30	8

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**22**	(18)	**(9)**	29
Interest rate contracts	**(173)**	(86)	**(694)**	703
Commodity contracts	**9**	(23)	**(8)**	(6)
Other contracts	**7**	(3)	**15**	(4)
Net investment hedges				
Foreign exchange contracts	**(63)**	25	**(66)**	(42)
	(198)	(105)	**(762)**	680
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(5)**	(2)	**10**	(5)
Interest rate contracts[2]	**30**	43	**74**	89
Commodity contracts[3]	**2**	5	**14**	1
Other contracts[4]	**(5)**	-	**(12)**	-
	22	46	**86**	85
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**130**	1	**158**	24
Commodity contracts[3]	**-**	-	**3**	(2)
	130	1	**161**	22

1 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
2 *Reported as an increase to Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $37 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 52 months as at September 30, 2014.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**(568)**	319	**(510)**	(382)
Interest rate contracts[2]	**1**	(2)	**3**	(7)
Commodity contracts[3]	**146**	20	**447**	124
Other contracts[4]	**5**	(1)	**12**	3
Total unrealized derivative fair value gains/(loss)	**(416)**	336	**(48)**	(262)

1 *Reported within Transportation and other services revenues (2014 - $254 million loss; 2013 - $165 million loss) and Other income/(expense) (2014 - $256 million loss; 2013 - $217 million loss) in the Consolidated Statements of Earnings.*

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

3 *Reported within Transportation and other services revenues (2014 - $395 million gain; 2013 - $197 million gain), Commodity costs (2014 - $57 million gain; 2013 - $6 million gain) and Operating and administrative expense (2014 - $5 million loss; 2013 - $79 million loss) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at September 30, 2014. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

	September 30, 2014	December 31, 2013
(millions of Canadian dollars)		
Canadian financial institutions	**78**	230
United States financial institutions	**67**	227
European financial institutions	**51**	192
Other[1]	**113**	97
	309	746

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

As at September 30, 2014, the Company had provided letters of credit totalling $205 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The

Company held nil cash collateral on derivative asset exposures at September 30, 2014 and $18 million of cash collateral at December 31, 2013.

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The

Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

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

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

September 30, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**22**	**-**	**22**
Interest rate contracts	**-**	**18**	**-**	**18**
Commodity contracts	**19**	**37**	**100**	**156**
Other contracts	**-**	**12**	**-**	**12**
	19	**89**	**100**	**208**
Long-term derivative assets				
Foreign exchange contracts	**-**	**44**	**-**	**44**
Interest rate contracts	**-**	**53**	**-**	**53**
Commodity contracts	**-**	**11**	**22**	**33**
Other contracts	**-**	**10**	**-**	**10**
	-	**118**	**22**	**140**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(203)**	**-**	**(203)**
Interest rate contracts	**-**	**(88)**	**-**	**(88)**
Commodity contracts	**(10)**	**(130)**	**(81)**	**(221)**
	(10)	**(421)**	**(81)**	**(512)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(838)**	**-**	**(838)**
Interest rate contracts	**-**	**(620)**	**-**	**(620)**
Commodity contracts	**-**	**(356)**	**(161)**	**(517)**
	-	**(1,814)**	**(161)**	**(1,975)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(975)**	**-**	**(975)**
Interest rate contracts	**-**	**(637)**	**-**	**(637)**
Commodity contracts	**9**	**(438)**	**(120)**	**(549)**
Other contracts	**-**	**22**	**-**	**22**
	9	**(2,028)**	**(120)**	**(2,139)**

December 31, 2013	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	78	-	78
Interest rate contracts	-	183	-	183
Commodity contracts	6	42	70	118
Other contracts	-	6	-	6
	6	309	70	385
Long-term derivative assets				
Foreign exchange contracts	-	67	-	67
Interest rate contracts	-	250	-	250
Commodity contracts	-	72	23	95
Other contracts	-	1	-	1
	-	390	23	413
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(75)	-	(75)
Interest rate contracts	-	(403)	-	(403)
Commodity contracts	(9)	(248)	(102)	(359)
	(9)	(726)	(102)	(837)
Long-term derivative liabilities				
Foreign exchange contracts	-	(470)	-	(470)
Interest rate contracts	-	(69)	-	(69)
Commodity contracts	-	(701)	(155)	(856)
	-	(1,240)	(155)	(1,395)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(400)	-	(400)
Interest rate contracts	-	(39)	-	(39)
Commodity contracts	(3)	(835)	(164)	(1,002)
Other contracts	-	7	-	7
	(3)	(1,267)	(164)	(1,434)

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

September 30, 2014	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	3	Forward gas price	3.49	5.36	4.41	\$/mmbtu[3]
Crude	3	Forward crude price	74.69	95.20	82.27	\$/barrel
NGL	3	Forward NGL price	0.24	2.22	1.34	\$/gallon
Power	(151)	Forward power price	42.02	77.90	59.47	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(12)	Forward gas price	2.03	5.43	4.20	\$/mmbtu[3]
Crude	16	Forward crude price	71.62	115.61	89.77	\$/barrel
NGL	12	Forward NGL price	0.23	2.32	1.52	\$/gallon
Commodity options[2]						
Crude	-	Option volatility	14%	20%	17%	
NGL	6	Option volatility	25%	38%	28%	
	(120)					

1 *Financial and physical forward commodity contracts are valued using a market approach valuation technique.*
2 *Commodity options contracts are valued using an option model valuation technique.*
3 *One million British thermal units (mmbtu).*

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

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

	Nine months ended September 30,	
	2014	2013
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(164)**	(24)
Total gains/(loss)		
Included in earnings[1]	**29**	(92)
Included in OCI	**4**	(2)
Settlements	**11**	(10)
Level 3 net derivative liability at end of period	**(120)**	(128)

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at September 30, 2014 or 2013.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $99 million at September 30, 2014 (December 31, 2013 - $103 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $306 million as at September 30, 2014 (December 31, 2013 - $287 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. As at September 30, 2014, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2013 - $580 million).

As at September 30, 2014, the Company's long-term debt had a carrying value of $30,835 million (December 31, 2013 - $25,168 million) and a fair value of $34,174 million (December 31, 2013 - $27,469 million).

NET INVESTMENT HEDGES

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

During the nine months ended September 30, 2014, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of $97 million (2013 - unrealized loss of $16 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of $66 million (2013 - unrealized loss of $42 million) in OCI. The Company also recognized a realized gain of $8 million (2013 - realized gain of $12 million) in OCI associated with the settlement of foreign exchange forward contracts that had matured during the period. There was no ineffectiveness during the nine months ended September 30, 2014 (2013 - $nil).

13. INCOME TAXES

The effective income tax rates for the three and nine months ended September 30, 2014 were 47.7% and 22.5%, respectively (2013 - 35.7% and 31.5%, respectively). The higher effective income tax rate for the nine months ended September 30, 2013 was largely attributable to a prior year adjustment. The higher effective income tax rate for the three months ended September 30, 2014 is mainly due to a higher benefit of rate-regulated accounting for income taxes relative to earnings in the quarter.

14. RETIREMENT AND POSTRETIREMENT BENEFITS

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

NET BENEFIT COSTS RECOGNIZED

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Benefits earned during the period	**29**	30	**88**	87
Interest cost on projected benefit obligations	**25**	23	**77**	66
Expected return on plan assets	**(32)**	(27)	**(96)**	(79)
Amortization of prior service costs	**-**	-	**1**	1
Amortization of actuarial loss	**7**	14	**21**	40
Net benefit costs on an accrual basis[1,2]	**29**	40	**91**	115

1 *Included in net benefit costs for the three and nine months ended September 30, 2014 are costs related to OPEB of $3 million and $11 million, respectively (2013 - $4 million and $13 million, respectively).*

2 *For the three and nine months ended September 30, 2014, offsetting regulatory liabilities of $2 million and $5 million (2013 - $1 million and $3 million regulatory assets) have been recorded to the extent pension and OPEB costs are expected to be refunded to or collected from customers in future rates.*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Nine months ended September 30,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Contributions paid	**89**	104	**7**	8
Contributions expected to be paid in the next three months	**30**		**4**	
Total contributions expected to be paid in the year	**119**		**11**	

15. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

As at September 30, 2014, Enbridge holds an approximate 33.8% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA.

EEP is also working with the Michigan Department of Environmental Quality (MDEQ) to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at September 30, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($198 million after-tax attributable to Enbridge), which is an increase of US$86 million ($17 million after-tax attributable to Enbridge) as compared with December 31, 2013 and an increase of US$51 million ($12 million after-tax attributable to Enbridge) as compared with June 30, 2014. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. Of the total cost increase of US$51 million during the three months ended September 30, 2014, US$33 million is primarily related to the MDEQ approved Schedule of Work and completion of the dredge activities near Ceresco and Morrow Lake and US$18 million is related to an increase of estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates 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. Including EEP's remediation spending through September 30, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at September 30, 2014, 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, the Company filed a lawsuit against one insurer who is disputing recovery eligibility for Line 6B costs. While the Company believes outstanding claims are covered under the policy, there can be no assurance the Company will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event 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 10 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.

At September 30, 2014, 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$3.7 million related to civil penalties assessed by the Pipeline and Hazardous Materials Safety Administration, which EEP paid during the third quarter of 2012. The total also included an amount of US$40 million related to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$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 measures directed toward enhancing spill prevention, leak detection, emergency response to environmental events and the cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company’s view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

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