ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 19, 2015 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2014, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). 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.

OVERVIEW

Enbridge, a Canadian Company, is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has significant and growing involvement in natural gas gathering, transmission and midstream businesses and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in more than 2,200 megawatts (MW) (1,600 MW net) of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal facilities. Enbridge employs more than 11,000 people, primarily in Canada and the United States.

The Company's activities are carried out through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Seaway Crude Pipeline System (Seaway Pipeline), Flanagan South Pipeline (Flanagan South), Southern Lights Pipeline, Spearhead Pipeline and Feeder Pipelines and Other.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, gathering and processing facilities and the Company's energy services businesses, along with renewable energy and transmission facilities.

Investments in natural gas pipelines include the Company's interests in the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance Pipeline and Canadian Midstream assets located in northeast British Columbia and northwest Alberta. The energy services businesses undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on Alliance Pipeline, Vector and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 33.7% economic interest in Enbridge Energy Partners, L.P. (EEP) and Enbridge's interests in both the Eastern Access and Lakehead System Mainline Expansion projects held through Enbridge Energy, Limited Partnership (EELP). Also within Sponsored Investments is the Company's overall 66.4% economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge, through its subsidiaries, manages the day-to-day operations of and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines, including the Lakehead Pipeline System (Lakehead System), which is the United States portion of the Enbridge mainline system, and transports, gathers, processes and markets natural gas and NGL. The primary operations of the Fund include renewable power generation, natural gas transmission (through its 50% interest in Alliance Pipeline) and crude oil and liquids pipeline transportation, which includes feeder pipelines and storage facilities in western Canada and an interest in the Southern Lights Pipeline.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, general corporate investments and financing costs not allocated to the business segments.

CANADIAN RESTRUCTURING PLAN

In December 2014, Enbridge announced its plan to transfer the majority of its Canadian Liquids Pipelines business comprising Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines (Athabasca) Inc. (EP Athabasca), and certain Canadian renewable energy assets with a combined carrying value of approximately $17 billion, with an associated secured growth capital program of approximately $15 billion, to the Fund (collectively, the Canadian Restructuring Plan). The transfer of the assets is expected to be completed in mid-2015. The Canadian Restructuring Plan was announced along with a 33% increase to the Company's next quarterly common share dividend effective on March 1, 2015 along with a corresponding new dividend payout policy range. For further details on the dividend increase and change in dividend payout policy range, refer to *Performance Overview – Dividends*.

The Canadian Restructuring Plan is intended to enhance Enbridge's value to investors while the Company executes its $44 billion growth capital program and to enhance the competitiveness of its funding costs for new organic growth opportunities and asset acquisitions. Transferring the assets to the Fund is expected to allow the majority of the growth capital program to be funded at an advantageous cost, while reducing the funding requirement at Enbridge. It also allows Enbridge to monetize a portion of its existing assets on favourable terms, releasing capital from the business for redeployment into future growth opportunities.

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

Enbridge's Canadian Liquids Pipelines includes its Canadian Mainline system held through EPI and its Regional Oil Sands System held through EP Athabasca. Both entities would be transferred from direct ownership by Enbridge to ownership by the Fund. Enbridge will retain operating responsibility for the Liquids Pipelines business, as it does for the assets currently held through the Fund and for those held through EEP, as well as responsibility for business development and project construction. In particular, Enbridge's enterprise-wide priority on the safety and reliability of its operations, including protection of employees, the public and the environment, will continue to apply to Canadian Liquids Pipelines.

The Fund currently already holds a number of Enbridge's renewable energy assets. The remainder of the existing Canadian renewable energy assets are held through EPI. Under the Canadian Restructuring Plan, the intention is to leave these renewable assets in EPI and include them with the transfer of the Canadian Liquids Pipelines business to the Fund. These renewable assets consist of Enbridge's interests in the Massif du Sud Wind Project (Massif du Sud), the Lac Alfred Wind Project (Lac Alfred) and the Saint Robert Bellarmin Wind Projects, all located in Quebec and the Blackspring Ridge Wind Project (Blackspring Ridge) in Alberta.

The Canadian Restructuring Plan contemplates the issuance by ENF of $600 million to $800 million of public equity per year from 2015 through 2018 in one or more tranches to fund its increasing investment in the Canadian Liquids Pipelines business through the Fund. Enbridge will retain an obligation to ensure the Fund has sufficient equity funding to undertake the growth capital program associated with the transferred assets and the amount of public equity to be issued by ENF would be adjusted as necessary to match its capacity to raise equity funding on favourable terms. Enbridge will contribute additional equity to ENF to maintain its current 19.9% interest. Enbridge would also take back a significant portion of the consideration for the assets transferred to the Fund in the form of additional equity in a subsidiary of the Fund.

As a result, Enbridge's aggregate economic interest in the Fund is expected to increase from its current level of 66.4% to approximately 90% initially, and then decline to approximately 80% by 2018 as ENF increases its investment in the Fund.

Enbridge also has under review a potential United States restructuring plan which would involve transfer of its directly held United States liquids pipelines assets to EEP. This review has not yet progressed to a conclusion. The proposed United States liquids pipelines restructuring plan is separate from the agreement to drop down Enbridge’s 66.7% interest in the United States segment of the Alberta Clipper pipeline to EEP, which closed on January 2, 2015. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Alberta Clipper Drop Down.*

PERFORMANCE OVERVIEW

	Three months ended December 31,		Year ended December 31,		
	2014	2013	**2014**	2013	2012
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**19**	46	**463**	427	697
Gas Distribution	**69**	80	**213**	129	207
Gas Pipelines, Processing and Energy Services	**185**	(325)	**571**	(68)	(377)
Sponsored Investments	**140**	79	**419**	268	283
Corporate	**(325)**	(151)	**(558)**	(314)	(129)
Earnings/(loss) attributable to common shareholders from continuing operations	**88**	(271)	**1,108**	442	681
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	4	**46**	4	(79)
	88	(267)	**1,154**	446	602
Earnings/(loss) per common share	**0.11**	(0.33)	**1.39**	0.55	0.78
Diluted earnings/(loss) per common share	**0.10**	(0.33)	**1.37**	0.55	0.77
Adjusted earnings[1]					
Liquids Pipelines	**199**	205	**858**	770	655
Gas Distribution	**68**	67	**177**	176	176
Gas Pipelines, Processing and Energy Services	**30**	17	**136**	203	176
Sponsored Investments	**123**	89	**429**	313	264
Corporate	**(11)**	(16)	**(26)**	(28)	(30)
	409	362	**1,574**	1,434	1,241
Adjusted earnings per common share[1]	**0.49**	0.44	**1.90**	1.78	1.61
Cash flow data					
Cash provided by operating activities	**656**	781	**2,547**	3,341	2,874
Cash used in investing activities	**(3,737)**	(3,277)	**(11,891)**	(9,431)	(6,204)
Cash provided by financing activities	**3,221**	2,744	**9,770**	5,070	4,395
Dividends					
Common share dividends declared	**297**	261	**1,177**	1,035	895
Dividends paid per common share	**0.350**	0.315	**1.40**	1.26	1.13
Revenues					
Commodity sales	**6,192**	6,939	**28,281**	26,039	18,494
Gas distribution sales	**835**	710	**2,853**	2,265	1,910
Transportation and other services	**1,770**	644	**6,507**	4,614	4,256
	8,797	8,293	**37,641**	32,918	24,660
Total assets	**72,857**	57,568	**72,857**	57,568	46,800
Total long-term liabilities	**42,306**	28,277	**42,306**	28,277	25,227

1 Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 10.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $1,154 million ($1.39 per common share) for the year ended December 31, 2014 compared with $446 million ($0.55 per common share) for the year ended December 31, 2013 and $602 million ($0.78 per common share) for the year ended December 31, 2012. The Company has continued to deliver significant earnings growth from operations over the course of the last three years, as discussed below in *Performance Overview – Adjusted Earnings.* However, the positive impact of this growth and the comparability of the Company's earnings are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes that over the long-term it supports the reliable cash flows and dividend growth upon which its investor value proposition is based. Earnings for 2014 and 2012 were also negatively impacted by the tax effect of the transfer of assets between entities under common control of Enbridge. Intercompany gains realized as a result of these transfers for both years have been eliminated for accounting purposes. However, as these transactions involved the sale of shares and partnership units, all tax consequences have remained in consolidated earnings and resulted in charges of $157 million and $56 million in 2014 and 2012, respectively. For further details, refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions.*

Also impacting the comparability of earnings year-over-year were costs and related insurance recoveries associated with the Line 6B crude oil release. Earnings for the years ended December 31, 2014, 2013 and 2012 included EEP's cost estimates relating to the Line 6B crude oil release of US$86 million ($12 million after-tax attributable to Enbridge), US$302 million ($44 million after-tax attributable to Enbridge) and US$55 million ($8 million after-tax attributable to Enbridge), respectively. The aforementioned costs are before insurance recoveries and exclude potential additional fines and penalties other than the fines and penalties discussed under *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Line 6B Crude Oil Release.* For the years ended December 31, 2013 and 2012, EEP recognized insurance recoveries of US$42 million ($6 million after-tax attributable to Enbridge) and US$170 million ($24 million after-tax attributable to Enbridge), respectively, related to the Line 6B crude oil release. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Insurance Recoveries*. Within Liquids Pipelines, 2014 and 2013 earnings reflected remediation and long-term stabilization costs of approximately $4 million and $56 million after-tax and before insurance recoveries, respectively, related to the Line 37 crude oil release that occurred in June 2013. In 2014, Enbridge recognized insurance recoveries of $8 million after-tax related to the Line 37 crude oil release. Refer to *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release.*

Other significant items impacting the comparability of the Company's year-over-year earnings were a $57 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) as well as a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. These transactions were recognized in 2014.

Finally, the Company's 2013 earnings reflected certain out-of-period adjustments that also impact the comparability of earnings between years. The out-of-period adjustments included 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 Gas Distribution, an out-of-period adjustment of $56 million after-tax was recognized reflecting an increase to gas transportation costs which had incorrectly been deferred.

Fourth quarter performance drivers were largely consistent with year-to-date trends and continued to be impacted by changes in unrealized fair value derivative and foreign exchange gains and losses. Aside from the operating factors discussed in *Performance Overview – Adjusted Earnings*, factors unique to the fourth quarter of 2014 included the impact of the tax effect associated with the transfer of assets between entities under common control of Enbridge, as noted above. Finally, the fourth quarter of 2014 included a $14 million after-tax gain recognized on the disposal of non-core assets within Offshore and leak insurance recoveries recognized from the June 2013 Line 37 crude oil release.

ADJUSTED EARNINGS

The Company's investor value proposition focuses on visible growth, a reliable business model and a growing income stream, supported by a rigorous focus on safe and reliable operations and a disciplined approach to investment and project execution. The Company has consistently delivered on this proposition, growing adjusted earnings from $1.61 per common share in 2012 to $1.78 per common share in 2013 and $1.90 per common share in 2014. This growth is a reflection of the strength of Enbridge's existing asset portfolio combined with the successful execution of its large growth capital program, which saw a number of new assets placed into service over this period.

The combination of strong core assets and the successful execution of the growth capital program were particularly evident in the Company's Liquids Pipelines and Sponsored Investments segments and were significant drivers of the Company's overall adjusted earnings growth over the past three years. Within Liquids Pipelines, Canadian Mainline adjusted earnings growth was largely the result of higher throughput from growing crude oil supply from western Canada and higher downstream refinery demand. Additionally, successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers also drove an increase in throughput, most notably in 2014.

New Liquids Pipelines assets placed into service in the past three years within Regional Oil Sands System, including the Woodland and Wood Buffalo pipelines completed in late 2012 and the Norealis Pipeline completed in 2014, contributed to adjusted earnings growth. In the fourth quarter of 2014, the Company placed into service Flanagan South and Seaway Crude Pipeline System Twin (Seaway Pipeline Twin). The two projects are key components of the Company's Gulf Coast Access program, which provides connectivity for producers in western Canada and the Bakken to the United States Gulf Coast refining hub. Both of the projects provided incremental earnings for the Company in the fourth quarter of 2014 and are expected to have a more significant impact on adjusted earnings growth in 2015.

Enbridge's sponsored vehicles, EEP and the Fund, also contributed positively to adjusted earnings growth. EEP adjusted earnings reflected increased contributions from its liquids business due to new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on its 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 Program. Enbridge also benefitted through its 75% interest in the United States portion of the Eastern Access expansion projects held through 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. Within the Fund, adjusted earnings growth reflected the benefit of an increased asset base that resulted from Enbridge's asset drop downs that occurred in 2011, 2012 and most recently in the fourth quarter of 2014.

Gas Pipelines, Processing and Energy Services 2014 adjusted earnings decreased compared with the previous year due in large part to market factors impacting the Company's Energy Services businesses and Aux Sable facilities. 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 Energy Services following a very strong 2013 fiscal year. Aux Sable adjusted earnings reflected a downward trend over the past two years due to lower fractionation margins and lower volumes at its upstream processing plants.

A key element of Enbridge's strategy is to secure the longer-term future through developing new platforms for growth and diversification. Examples of diversification initiatives that drove year-over-year growth in adjusted earnings included the Company's investment in Canadian Midstream assets, being the Cabin Gas Plant (Cabin) and the Pipestone and Sexsmith gathering systems (together, Pipestone and Sexsmith), as well as Enbridge's continued investment in renewable energy assets through the acquisition of new wind farms and additional interests in existing wind farm assets that it owns with others.

The Company's 2014 adjusted earnings were impacted by higher preference share dividends in its Corporate segment, as well as higher interest expense across various business segments reflecting incremental preference share and debt funding incurred to fund its growth capital program.

With respect to the fourth quarter of 2014, many of the annual trends discussed above were also the factors in driving adjusted earnings growth over the fourth quarter of 2013. In Liquids Pipelines, higher throughput on Canadian Mainline and new assets placed into service across the segment provided a favourable uplift to 2014 fourth quarter adjusted earnings. However, this growth was more than offset by a lower quarter-over-quarter toll on Canadian Mainline. In the fourth quarter of 2013, Regional Oil Sands System included a favourable adjustment related to a reduction in third party revenue sharing with the founding shipper on the Athabasca Pipeline. Although this adjustment had no impact on full year 2013 adjusted earnings, it resulted in higher adjusted earnings in the fourth quarter of 2013 compared with the equivalent 2014 period. Excluding the impact of this 2013 adjustment, Regional Oil Sands System adjusted earnings were comparable between the fourth quarter periods.

Energy Services earnings for the fourth quarter were higher than the comparable period in 2013 as wider location and crude grade differentials enabled it to capture more profitable margin and tank management arbitrage opportunities, which helped to partially offset the decrease in adjusted earnings during the first nine months of 2014 due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with unrecovered demand charges.

Impact of the Recent Decline in Commodity Prices

Enbridge's value proposition is built on the foundation of its reliable business model. The majority of its earnings and cash flow are generated from tolls and fees charged for the energy delivery services that it provides to its customers. Business arrangements are structured to minimize exposure to commodity price movements and any residual exposure is closely monitored and managed through disciplined hedging programs. Commercial structures are typically designed to provide a measure of protection against the risk of a scenario where falling commodity prices indirectly impact the utilization of the Company's facilities. Protection against volume risk is achieved through regulated cost of service tolling arrangements, long term take-or-pay contract structures and fee for service arrangements with specific features to mitigate exposure to falling throughput.

Smaller components of Enbridge's earnings are more exposed to the impacts of commodity price volatility. This includes Energy Services, where opportunities to benefit from location, time and quality differentials can be affected by commodity market conditions. They also include the Company's interest in Aux Sable's natural gas fractionation facilities and EEP's natural gas gathering and processing businesses, however, the impact on Enbridge's overall financial performance is relatively small and any inherent commodity price risk is mitigated by hedging programs within these businesses and Enbridge's partial ownership interest.

The latter half of 2014 has seen a dramatic decline in the price of crude oil, natural gas and NGL and other commodities whose prices are highly correlated to crude oil. Benchmark prices for crude which had been trading over US$105 per barrel in June 2014, fell to as low as US$53 per barrel by end of the year as a result of significant increases in production both inside and outside of North America in the face of relatively tepid growth in world-wide demand. Entering 2015, prices continue to be weak and are expected to remain volatile in the near-term as the market seeks to re-balance supply and demand. The current commodity price environment has had an impact on shippers on Enbridge's pipelines who have responded to price declines by reducing investment in exploration and development programs for 2015. However, this is not expected to materially impact the financial performance of the Company. Notwithstanding the price decline, it is expected that existing conventional and oil sands production should be more than sufficient to support continued high utilization of the liquids pipelines mainline. Entering 2015, nominations for service on the pipelines have continued to exceed available capacity on the system, resulting in apportionment of nominated volumes. Due to the nature of the commercial structures described above, Enbridge's earnings and cash flow are not expected to be materially affected by the current low price environment.

The decline in oil prices is also causing some sponsors of oil sands development programs to reconsider the timing of previously announced upstream development projects. Cancellation or deferral of these projects would affect longer-term supply growth from the Western Canadian Sedimentary Basin (WCSB). Enbridge's existing growth capital program described under *Growth Projects – Commercially Secured Projects* has been commercially secured and is expected to generate reliable and predictable earnings growth through 2018 and beyond. Importantly, after taking into account the potential for some of the less profitable projects to be cancelled or deferred in an environment where low prices persist, Enbridge's most recent near-term supply forecast reaffirms that the expansions and extensions of its liquids pipeline system currently in progress will provide very cost-effective transportation services to key markets in North America.

In the current low-price environment, Enbridge is working closely with producers to find ways to enhance capacity and provide enhanced access to markets in order to alleviate locational pricing discounts. Examples include the Company's recently completed Flanagan South and Seaway Pipeline Twin projects, which increase access to the United States Gulf Coast refining hub.

CASH FLOWS

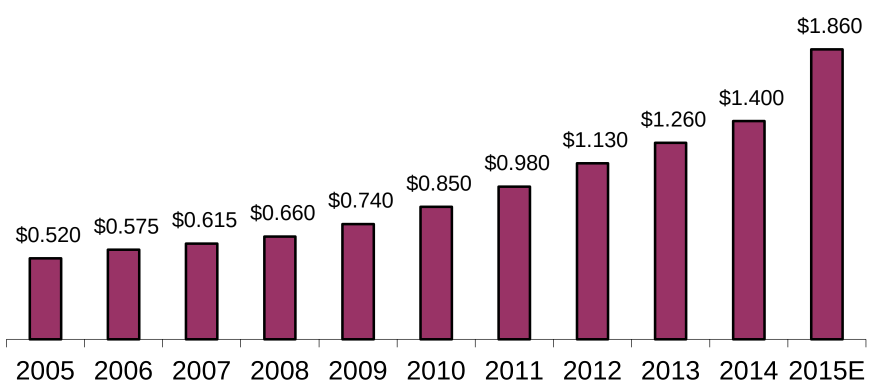
Cash provided by operating activities was $2,547 million for the year ended December 31, 2014, mainly driven by strong operating performance from the Company's core assets, particularly from Liquids Pipelines and Sponsored Investments, and the cash flow generation from growth projects placed into service in recent years. Partially offsetting these cash inflows were changes in operating assets and liabilities as further discussed in *Liquidity and Capital Resources*.

In 2014, the Company was active in the capital markets with the issuance of $1,365 million in preference shares, common shares of approximately $478 million and $6,921 million in medium-term notes and also maintained its liquidity through secured credit facilities. The proceeds of the capital market transactions, together with additional borrowings from its credit facilities, cash generated from operations and cash on hand were more than sufficient to finance the Company's nearly $10 billion of projects placed into service in 2014 and are expected to provide financing flexibility for the Company's growth capital program in 2015.

DIVIDENDS

The Company has paid common share dividends since it became a publicly traded company in 1953. In December 2014, the Company announced a 33% increase in its quarterly dividend to $0.465 per common share, or $1.860 annualized, effective March 1, 2015, in conjunction with the announcement of the Canadian Restructuring Plan. For more details, refer to *Canadian Restructuring Plan*.

Dividends per Common Share



Also in December 2014, Enbridge's Board of Directors approved a revised dividend payout policy range of 75% to 85% of adjusted earnings. The previous payout policy range was 60% to 70%. In 2014, the dividend payout was 74% (2013 - 71%; 2012 - 70%) of adjusted earnings per share. The revised dividend policy is supported by the funding progress achieved to date and increasing internally generated free cash flow. For the 10-year period ended December 2014, the Company's compound annual average dividend growth rate was 13.6%.

REVENUES

The Company generates revenues from three primary sources: commodity sales, gas distribution sales and transportation and other services. Commodity sales of $28,281 million for the year ended December 31, 2014 (2013 - $26,039 million; 2012 - $18,494 million) were generated through the Company's energy services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas and NGL to generate a margin, which is typically a small fraction of gross revenue. While sales revenues generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices.

Gas distribution sales are primarily earned by EGD and are recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are driven by volumes delivered, which vary with weather and customer base, as well as regulator-approved rates. The cost of natural gas is charged to customers through rates but does not ultimately impact earnings due to the flow-through nature of these costs.

Transportation and other services revenues are earned from the Company's crude oil and natural gas pipeline transportation businesses and also includes power production revenues from the Company's portfolio of renewable and power generation assets. For the Company's transportation assets operating under market-based arrangements, revenues are driven by volumes transported and tolls. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of the Company's cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on the Company's core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past two years.

The Company's revenues also included changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The unrealized mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but the Company believes over the long-term, the economic hedging program supports reliable cash flows and dividend growth.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''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 the following: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; the Canadian Restructuring Plan; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, 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; final approval of definitive transfer terms by Enbridge and ENF and the Fund; receipt of all necessary shareholder and regulatory approvals that may be required for the Canadian Restructuring Plan; and *weather. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, the impact of the Canadian Restructuring Plan on Enbridge, the adjusted dividend payout policy or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates and expected capital expenditures, include the following: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; 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) conveys 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 performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. The table below summarizes the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS

	2014	2013	2012
(millions of Canadian dollars)			
Earnings attributable to common shareholders	**1,154**	446	602
Adjusting items[1]:			
Changes in unrealized derivative fair value and intercompany foreign exchange loss[2]	**320**	843	536
Make-up rights adjustments	**17**	50	-
Leak remediation costs, net of leak insurance recoveries	**8**	94	(15)
Warmer/(colder) than normal weather	**(36)**	(9)	23
Gains on sale of non-core assets and investment	**(71)**	(2)	-
Asset impairment losses	**2**	6	105
Project development and transaction costs	**14**	-	-
Tax on intercompany gains on sale of assets	**157**	-	56
Tax related adjustments	**-**	(19)	(9)
Out-of-period adjustments	**-**	25	(1)
Other	**9**	-	(56)
Adjusted earnings	**1,574**	1,434	1,241

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

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

CORPORATE VISION AND STRATEGY

VISION

Enbridge's vision is to be the leading energy delivery company in North America. In pursuing this vision, the Company plays a critical role in enabling the economic well-being and quality of life of North Americans, who depend on access to plentiful energy. The Company transports, distributes and generates energy, and its primary purpose is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.

Among its peers, Enbridge strives to be the leader, which means not only leadership in value creation for shareholders but also leadership with respect to worker and public safety and environmental protection associated with its energy delivery infrastructure, as well as in customer service, community investment and employee satisfaction. Driven by this vision, the Company delivers value for shareholders from a proven and unique value proposition, which combines visible growth, a reliable business model and a dependable and growing income stream.

STRATEGY

The Company's initiatives centre around eight areas of strategic emphasis in four key focus areas. These strategies are reviewed at least annually with direction from the Company's Board of Directors.

COMMITMENT TO SAFETY AND OPERATIONAL RELIABILITY	
EXECUTE	**SECURE THE LONGER-TERM FUTURE**
• *Focus on project management* • *Preserve financing strength and flexibility*	• *Strengthen core businesses* • *Develop new platforms for growth and diversification*
MAINTAIN THE FOUNDATION	
• *Uphold Enbridge values* • *Maintain the Company's social license to operate* • *Attract, retain and develop highly capable people*	

Commitment to Safety and Operational Reliability

Safety and operational reliability remains the Company's number one priority and sets the foundation for the strategic plan. The commitment to safety and operational reliability means achieving industry leadership in safety (process, public and personal) and ensuring the reliability and integrity of the systems the Company operates in order to generate, transport and deliver the energy society counts on and to protect the environment.

Under the umbrella of the Company's Operational Risk Management (ORM) Plan introduced in 2010, Enbridge has undertaken extensive maintenance, integrity and inspection programs across its pipeline systems. The ORM Plan has resulted in strong improvements in the area of safety and operational risk management, bolstering incident response capabilities, employee and public safety protocols and improved communications with landowners and first responders. In addition, an enterprise-wide safety and risk management framework has been implemented to ensure the Company identifies, prioritizes and effectively prevents and mitigates risks across the enterprise. Supporting these initiatives is a safety culture that strives towards a target of 100% safe operations, with a belief that all incidents can be prevented. To achieve the goal of industry leadership, the Company measures its performance as compared to standard industry performance, transparently reports its results and continues to use external assessments to measure its performance.

Execute

Focus on Project Management

Enbridge's objective is to safely deliver projects on time and on budget and at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. With an approximate $34 billion portfolio of commercially secured growth projects, successful project execution is critical to achieving the Company's long-term growth plan. Enbridge, through its Major Projects Group (Major Projects), continues to build upon and enhance the key elements of its rigorous project management processes including: employee and contractor safety; long-term supply chain agreements; quality design, materials and construction; extensive regulatory and public consultation; robust cost, schedule and risk controls; and efficient project transition to operating units.

Preserve Financing Strength and Flexibility

The maintenance of adequate financing strength and flexibility is crucial to Enbridge's growth strategy. Enbridge's financing strategies are designed to ensure the Company has sufficient financial flexibility to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain strong credit ratings, diversify its funding sources and maintain substantial standby bank credit capacity and access to capital markets in both Canada and the United States. As part of the Company's risk management policy, the Company engages in a comprehensive long-term economic hedging program to mitigate the impact of fluctuations in interest rates, foreign exchange and commodity price on the Company's earnings. This program supports one of the key tenets of the Company's investor value proposition, a reliable business model.

Enbridge has also actively used its sponsored vehicles, primarily through asset drop downs, to cost-effectively fund a portion of its large growth capital program. In 2014, the Company announced its proposed Canadian Restructuring Plan, which will transfer the majority of its Canadian Liquids Pipelines business and certain renewable energy assets to the Fund. See *Canadian Restructuring Plan*. For further discussion on the Company's financing strategies, refer to *Liquidity and Capital Resources*.

The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and assessed using strict operating, strategic and financial criteria with the objective of ensuring the effective deployment of capital and the enduring financial strength and stability of the Company.

Secure the Longer-Term Future

Strengthen Core Businesses

Within the Company's crude oil transportation business, strategies continue to be focused on providing access to new markets for growing production from western Canada and Bakken regions, optimizing and expanding mainline operations and expanding regional oil sands infrastructure. The Company's assets are strategically located and well-positioned to capitalize on these opportunities. Over the past year, Enbridge has significantly advanced its market access programs that provide shippers with greater connectivity to key markets and secure more favourable pricing for their products. In 2014, the Company significantly advanced its Gulf Coast Access program through the completion of Flanagan South and Seaway Pipeline Twin. Combined, the two projects have the capability of providing up to 600,000 barrels per day (bpd) of incremental capacity to transport crude oil from the oil sands or Bakken regions to the key United States Gulf Coast refining hub. Enbridge continued to optimize and expand its mainline system and in 2014, throughput reached record levels driven by strong supply and refinery demand in combination with efforts by the Company to maximize capacity and throughput and to enhance scheduling efficiency with shippers. As new projects come into service, one of the key objectives is to fully integrate them within Enbridge's existing portfolio.

While executing its record growth capital program, the Company has also been undertaking an extensive integrity program across its liquids and gas systems. In addition, in 2014, Enbridge completed the replacement of Line 6B and an in-depth inspection of Line 9B as part of the Line 9B reversal and expansion project. Also in 2014, the Company announced the Line 3 Replacement Program (L3R Program). While the L3R Program will not increase the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system and enhance the flexibility on the mainline system allowing the Company to further optimize throughput.

The focus in Regional Oil Sands Systems is to optimize existing asset corridors to secure incremental supply expected from the western Canadian oil sands projects over the next decade. Within this regional focus area, Enbridge has approximately $6 billion of regional infrastructure currently under development which is expected to enter service from 2014 to 2017. In the Bakken region, Enbridge and EEP's growth is focused on the development and construction of the US$2.6 billion Sandpiper Project (Sandpiper). Due to be placed into service in 2017, Sandpiper will provide North Dakota producers enhanced access to premium light crude oil markets.

With the majority of the Company's growth capital projects expected to come into service by the end of 2018, the Company's liquids business is also carrying out initiatives to secure and extend the growth beyond 2018. The proposed structure announced in the Canadian Restructuring Plan is expected to help position the Company to support future investments and extend growth past 2018 by improving the competitiveness of its funding costs for new organic growth opportunities and asset acquisitions. For further details on the Canadian Restructuring Plan, refer to *Canadian Restructuring Plan.*

The Company's natural gas strategies include leveraging the competitive advantages of its existing assets and expanding its footprint in emerging areas. Combined, Alliance Pipeline and the Aux Sable NGL fractionation plant are well-positioned to provide liquids-rich gas transportation and processing to developing regions in northeast British Columbia, western Alberta and the Bakken. Alliance Pipeline has also made significant progress in securing precedent agreements with shippers past December 2015 when the majority of its existing contracts are set to expire. For further details, refer to *Sponsored Investments – Enbridge Income Fund – Alliance Pipeline Recontracting.*

The Company expanded its Canadian midstream infrastructure in 2014 with the completion of the Pipestone and Sexsmith projects which included sour gas gathering and compression facilities located in the Peace River Arch (PRA) region of northwest Alberta. The Company is seeking to expand its Canadian midstream footprint, with the primary focus in the liquids-rich Montney and Duvernay formations in western Canada. In addition to these onshore strategies, the Company continues to pursue crude oil and natural gas gathering pipeline opportunities for ultra-deep projects in the Gulf of Mexico. In the fourth quarter of 2014, the Company placed the Jack St. Malo portion of the Walker Ridge Gas Gathering System (WRGGS) into service and expects to place the Big Foot gas portion of WRGGS along with the Big Foot Oil Pipeline (Big Foot Pipeline) into service in the third quarter of 2015. Growth in Offshore is expected to continue as the Heidelberg Oil Pipeline (Heidelberg Pipeline) is currently under construction and is expected to enter service in 2016. Additionally, in early January 2015, the Company announced it was selected to build, own and operate the Stampede Oil Pipeline (Stampede Pipeline), a crude oil pipeline in the Gulf of Mexico to connect to Hess Corporations' (Hess) Stampede development.

Enbridge's natural gas distribution business in eastern Canada is the largest in Canada with over two million customers. In 2014, the Ontario Energy Board (OEB) approved the second generation customized Incentive Rate (IR) Plan which establishes natural gas distribution rates over a five-year period from 2014 to 2018. A key tenet of the customized IR Plan is that it allows EGD to recover costs for significant capital investment, including the Greater Toronto Area (GTA) Project which will increase capacity and reliability for EGD's customers and diversify gas supply. The customized IR Plan also allows EGD an opportunity to earn above an allowed return on equity (ROE), with any return over the allowed ROE for a given year to be shared equally with customers. The customized IR Plan provides stability in earnings and cash flow to Enbridge's overall business model.

Develop New Platforms for Growth and Diversification

The development of new platforms to diversify and sustain long-term growth is an important strategic priority. The Company is currently focusing its development and diversification efforts towards securing investment in additional renewable energy and power transmission facilities and in energy marketing, as well as developing opportunities in gas-fired power generation, liquefied natural gas (LNG) development and select energy delivery assets outside North America. The Company also invests in early stage energy technologies that complement the Company's core businesses.

Since the end of 2013, Enbridge has continued to grow its renewable power portfolio, placing into service Blackspring Ridge in Alberta and the Keechi Wind Project (Keechi) in Texas. The Company also increased its interest in the 300-MW Lac Alfred to 67.5% and in the 150-MW Massif du Sud to 80%. Late in 2014, Enbridge finalized the purchase of an 80% interest in a portfolio of two wind farms located in Texas and Indiana. With the closing of this transaction, Enbridge's enterprise-wide renewable energy portfolio has a net generation capacity of approximately 1,600 MW.

Maintain the Foundation

Uphold Enbridge Values

Enbridge adheres to a strong set of core values that govern how it conducts its business and pursues strategic priorities, as articulated in its value statement: "Enbridge employees demonstrate integrity, safety and respect in support of our communities, the environment and each other". Employees are expected to uphold these values in their interactions with each other, customers, suppliers, landowners, community members and all others with whom the Company deals with and ensure the Company's business decisions are consistent with these values. Employees and contractors are required, on an annual basis, to certify their compliance with the Company's Statement on Business Conduct.

Maintain the Company's Social License to Operate

Earning and maintaining "social license" – the acceptance by the communities in which the Company operates or is proposing new projects – is critical to Enbridge's ability to execute on its growth plans. To earn the public's trust, and to protect and reinforce the Company's reputation with its stakeholders, Enbridge is committed to integrating Corporate Social Responsibility (CSR) into every aspect of its business. The Company defines CSR as conducting business in an ethical and responsible manner, protecting the environment and the safety of people, providing economic and other benefits to the communities in which the Company operates, supporting universal human rights and employing a variety of policies, programs and practices to manage corporate governance and ensure fair, full and timely disclosure. The Company provides its stakeholders with open, transparent disclosure of its CSR performance and prepares its annual CSR Report using the Global Reporting Initiative G3.1 sustainability reporting guidelines, which serve as a generally accepted framework for reporting on an organization's economic, environmental and social performance.

An important component of CSR at Enbridge is the Neutral Footprint Program. Through Enbridge's Neutral Footprint Program, the Company has committed to reducing the environmental impact of its pipeline expansion projects within five years of their occurrence. The Company seeks to meet this commitment by:

- planting a tree for every tree the Company removes;
- conserving an acre of natural habitat for every acre the Company permanently alters; and
- growing the Company's renewable energy business at a pace that matches increased energy consumption in its liquids pipelines business through generation of an additional kilowatt hour of renewable energy for every additional kilowatt hour of energy used to power its pipeline projects.

Since it began five years ago, the Neutral Footprint Program has met its targets for trees, hectares and kilowatt hours, and in 2014 continued to be on track to do so. In 2014, the Company also consulted with internal and external stakeholders on the purpose and design of the program moving forward. In 2015, the Company plans to update the program to address the feedback it has received and incorporate new approaches to engaging with its Right of Way Communities on environmental conservations projects and opportunities.

The Company's CSR Report can be found at http://csr.enbridge.com and progress updates on the Company's Neutral Footprint initiatives can be found at http://www.enbridge.com/neutralfootprint and in the annual CSR Report. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of this MD&A.***

To complement community investments in its Canadian and United States operating areas, Enbridge created the energy4everyone foundation (the Foundation) in 2009. The Foundation aims to leverage the expertise and resources of the Canadian energy industry to effect significant positive change through the delivery and deployment of affordable, reliable and sustainable energy services and technologies in communities in need around the world. To date, the Foundation has completed projects in Costa Rica, Ghana, Nicaragua, Peru and Tanzania.

Attract, Retain and Develop Highly Capable People

Investing in the attraction, retention and development of employees and future leaders is fundamental to executing Enbridge's growth strategy and creating sustainability for future success. The Company continues to focus on people-related areas, including broadening recruiting efforts beyond traditional industry and geographical reaches, ensuring succession capability through accelerated leadership development programs and enhancing career opportunities and building change management capabilities throughout the enterprise to ensure projects and initiatives achieve the intended benefits. Furthermore, Enbridge strives to maintain industry competitive compensation and retention programs that provide both short-term and long-term incentives.

INDUSTRY FUNDAMENTALS

SUPPLY AND DEMAND FOR LIQUIDS

Enbridge has an established and successful history of being the largest transporter of crude oil to the United States, the world's largest market. While United States' demand for Canadian crude oil production will support the use of Enbridge infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and Enbridge has a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets.

As discussed in *Performance Overview - Impact of the Recent Decline in Commodity Prices*, crude oil prices fell by close to 50% in the latter half of 2014. The international market for crude oil has seen a significant change in the supply including a significant increase in production from North American basins and increased production from Organization of the Petroleum Exporting Countries (OPEC). The reduction in price has had an impact on Enbridge's liquids pipelines' customers, who have responded by reducing their exploration and development spending for 2015.

Notwithstanding the recent price decline, the Enbridge system has thus far continued to be highly utilized. The mainline system continues to be subject to apportionment, as nominated volumes currently exceed current capacity on the system. Any impact to the financial performance of Enbridge's liquids pipelines business is expected to be relatively modest given the commercial arrangements which underpin the system and provide a significant measure of protection in a falling supply scenario. The recent decline in crude oil prices has caused some sponsors to reconsider the timing of their upstream oil sands development projects; however, recently updated forecasts of oil sands production suggest that long-term supply growth from the WCSB will not change materially.

Over the long-term, global energy consumption is expected to continue to grow, with the growth in crude oil demand primarily driven by emerging economies in non-Organisation for Economic Co-operation and Development (OECD) regions, such as China, India and the Middle East. In OECD countries, including Canada, the United States and western European nations, efficiency gains, conservation, limited population growth and a shift to alternative energy will reduce crude oil demand over the long-term. Accordingly, there is a strategic opportunity for North American producers to grow production to displace foreign imports and participate in the growing global demand outside North America.

In terms of supply, long-term global crude oil production is expected to continue to grow through 2040, with North America being a significant contributor to overall global supply. Growth in North America is largely driven by production from the oil sands, the Gulf of Mexico and the emergence and continued development of tight oil plays including the Bakken, Eagle Ford and Permian formations. Political uncertainty in certain oil producing countries, including Libya, Iran, Syria and Iraq, risk those regions' supply growth forecast and makes North America one of the more secure supply sources of crude oil. As witnessed in the latter half of 2014, North American supply growth can be influenced by macro-economic factors that drive down the global crude prices. Over the longer-term, North American production from tight oil plays, including the Bakken, is expected to grow as technology continues to improve well productivity and reduce costs. In Canada, the WCSB is viewed as one of the world's largest and most secure supply sources of crude oil. Investment in the WCSB is expected to remain strong over the longer-term due to technological advances and continued foreign investment. However, the pace of growth in North America could be tempered by a sustained period of low crude oil prices, as well as increasing environmental regulation in future years.

The combination of relatively flat domestic demand, growing supply and long-lead time to build pipeline infrastructure has led to a fundamental change in the North American crude oil landscape. In recent years, an inability to move increasing inland supply to tide-water markets has resulted in a divergence between West Texas Intermediate (WTI) and world pricing, resulting in lower netbacks for North American producers than could otherwise be achieved if selling into global markets. The impact of price differentials has been even more pronounced for western Canadian producers as insufficient pipeline infrastructure has resulted in a further discounting of Alberta crude against WTI. With a number of market access initiatives recently taken by the industry, including those introduced by Enbridge, the crude oil price differentials significantly narrowed in 2014 and resulted in higher netbacks for producers. However, as the supply in North America continues to grow, the growth and flexibility of pipeline infrastructure will need to keep pace with the sensitive demand and supply balance. Shippers also continue to seek alternative means of transportation, such as rail, to access higher netback markets as a result of a shortage of pipeline capacity; however, over the longer-term, the Company believes pipelines will continue to be the most cost-effective means of transportation in markets where the differential between North American and global oil prices remain narrow. Utilization of rail to transport crude is expected to be substantially limited to those markets not readily accessible by pipelines.

Enbridge's role in helping to address the evolving supply and demand fundamentals and alleviating price discounts for producers and supply costs to refiners is to provide expanded pipeline capacity and sustainable connectivity to alternative markets. In 2014, Enbridge reached a significant milestone in its Gulf Coast Access Program through the completion of Flanagan South and Seaway Pipeline Twin. Together, these projects have the capability of opening up to approximately 600,000 bpd of capacity to transport crude from the oil sands and Bakken regions to the United States Gulf Coast refining area. Significant steps were also achieved in the Company's Eastern Access Program, with the completion of the Line 6B replacement and expansion project in September 2014. The Eastern Access Program provides increased access to refineries in the upper midwest United States and eastern Canada.

As oil sands production in western Canada continues to grow, prices continue to be sensitive to capacity limitations to markets, heightening the need to expand access to growing Asian markets. Details of the Company's Northern Gateway Project (Northern Gateway), a proposed pipeline system from Alberta to the coast of British Columbia, and associated marine terminal, along with the Company's other projects under development, can be found in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development*.

SUPPLY AND DEMAND FOR NATURAL GAS AND NGL

Global energy demand is expected to increase as the global economy grows with most of this growth expected from non-OECD countries. Natural gas will play an important role to meet this energy demand and is anticipated to be one of the world's fastest growing energy sources. Most natural gas demand will stem from the need for greater power generation capacity; natural gas is a cleaner alternative to coal which has the largest market share for power generation. Within North America, United States natural gas demand is projected to be modest until the next wave of gas-intensive petrochemical facilities, LNG export facilities and gas-fired generation enters service, which is expected later this decade. Over the longer-term, higher United States natural gas demand is expected to be driven by the industrial sector and from power generation. Within Canada, natural gas demand growth is expected to be largely tied to oil sands development.

Similar to crude oil, robust North American supply from tight formations has created a demand and supply imbalance. North American supply continues to be dominated by natural gas development in the northeastern United States, primarily the dominant Marcellus shale, as well as the emerging Utica shale. The abundance of supply from these shale plays has fundamentally altered natural gas flow patterns in North America and largely displaced United States Gulf Coast and WCSB gas production. As a result, regional natural gas production, apart from the abundant production in the northeastern United States, has largely been flat or has declined over the past several years in response to robust growth in the Appalachian region and resulted in prolonged weak North American natural gas prices. While low natural gas prices are expected to be a key driver in future infrastructure growth and natural gas demand, it is also expected that gas supply will remain ample and could respond quickly to rising demand thereby limiting price advances.

With the weak natural gas price environment over the last several years, producers have shifted from dry gas drilling to developing rich gas reservoirs to take advantage of the relatively higher value of NGL inherent in the gas stream. NGL that can be extracted from liquids-rich gas streams include ethane, propane, butane and natural gasoline, which are used in a variety of industrial, commercial and other applications. Over the longer-term, the growth in NGL demand will be largely driven by ethane demand as it is the key feedstock to the United States Gulf Coast petrochemical industry which is currently undergoing significant expansion and once completed is expected to be the world's second lowest-cost ethylene producer. However, until this infrastructure is established, ethane prices and resulting extraction margins are expected to remain low due to the current oversupply and have resulted in ethane being retained in the gas stream rather than processed. Rapidly growing supplies of propane have also been placing downward pressure on prices and have prompted the expansion of export facilities. In Canada, the WCSB basin is well-situated to capitalize on the evolving NGL fundamentals as the Montney formation in northern British Columbia and the Duvernay shale in Alberta have significant liquids-rich resources at competitive costs. While longer-term NGL fundamentals suggest a positive outlook for growth, a sustained period of low crude oil prices and the related negative impact on NGL prices could temper future growth.

The recent decline in crude prices has had a direct impact on producers' oil focused drilling plans in 2015. Lower prices for NGL, which generally trade at a percentage of crude prices, will also cause a reduction in liquids-rich gas drilling and limit production growth. However, robust gas production from highly economic core areas within certain shale plays, particularly the Marcellus, is expected to offset any price related production declines over the next year. To the extent oil prices recover, the crude-to-gas price ratio is expected to rise from current levels. The immense and readily available gas supply within North America will continue to limit price increases. In this scenario, the crude-to-gas price ratio is expected to remain well above energy conversion value levels and continue to be supportive of NGL extraction.

The price for LNG in global markets has typically been more closely linked to crude oil prices, providing producers with an opportunity to capture more favourable netbacks on LNG exports from North America, if that pricing linkage is maintained. Based on the prospect for higher global LNG demand, the large resource base in western Canada and the changing North American natural gas flow patterns discussed above, there is an increasing probability that additional projects to export LNG from the continental United States or potentially off the west Coast of Canada will proceed. However, a sustained period of low crude oil prices or other changes in global supply and demand for natural gas could delay such opportunities.

In response to these evolving natural gas and NGL fundamentals, Enbridge believes it is well-positioned to provide value-added solutions to producers. Alliance Pipeline traverses through the heart of key liquids-rich plays in the WCSB and is uniquely configured to transport liquids-rich gas. Alliance Pipeline has developed new service offerings to best meet the needs of producers and shippers. The focus on liquids-rich gas development also creates opportunities for Aux Sable, an extraction and fractionation facility near Chicago, Illinois near the terminus of Alliance Pipeline. Enbridge is also responding to the need for regional infrastructure with additional investment in Canadian and United States midstream processing and pipeline facilities.

SUPPLY AND DEMAND FOR RENEWABLE ENERGY

The electrical generation and distribution network in North America is expected to undergo significant growth over the next 15 years. On the demand side, North American economic growth over the longer-term is expected to drive growing electricity demand, although continued efficiency gains are expected to make the economy less energy-intensive and temper demand growth. On the supply side, impending legislation in both Canada and the United States is expected to accelerate the retirement of aging coal-fired generation plants, resulting in a requirement for significant new generation capacity. While coal and nuclear facilities will continue to be a core component of power generation in North America, gas-fired and renewable energy facilities, including biomass, hydro, solar and wind, are expected to be the preferred sources to replace coal-fired generation due to their lower carbon intensities.

North American wind and solar resources fundamentals remain strong; in the United States there are nearly 66 gigawatts (GW) of installed wind power capacity and in Canada over nine GW of capacity. Solar resources in southwestern states such as Arizona, California and Nevada are considered to be some of the best in the world for large-scale solar plants and the United States currently has over 16 GW of installed solar photovoltaic capacity. However, expanding renewable energy infrastructure in North America is not without challenges. Growing renewable generation capacity is expected to necessitate substantial capital investment to upgrade existing transmission systems or, in many cases, build new transmission lines, as these high quality wind and solar resources are often found in regions that are not in close proximity to markets. Furthermore, the profitability of renewable energy projects, to date, has in part been supported by certain tax and government incentives. In the near-term, uncertainty over the continuing availability of tax or other government incentives and the ability to secure long-term power purchase agreements (PPA) through government or investor-owned power authorities may hinder the pace of future new renewable capacity development. However, continued improvement in technology and manufacturing capacity in the past few years has reduced capital costs associated with renewable energy infrastructure and has also improved yield factors of power generation assets. These positive developments are expected to render renewable energy more competitive and support ongoing investment over the long-term.

Enbridge continues to expand its renewable asset footprint and is Canada's second-largest wind power generator and second-largest solar power generator. Since the end of 2013, Enbridge placed into service the Blackspring Ridge and Keechi wind farms and also increased its ownership interest in Lac Alfred to 67.5% and in Massif du Sud to 80%. Late in 2014, Enbridge also finalized the purchase of an 80% interest in a portfolio of two wind farms located in Texas and Indiana from E.ON Climate and Renewables North America, LLC (E.ON), a subsidiary of E.ON SE. The Company will continue to seek new opportunities to grow its portfolio of renewable power generation businesses that meet its investment criteria.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

A key focus of Enbridge's corporate strategy is the successful execution of its growth capital program. In 2014, Enbridge successfully placed into service approximately $10 billion of growth projects across several business units. Enbridge also expanded its portfolio of commercially secured growth projects to $34 billion. All of these projects are expected to come into service by 2018; with more than $9 billion during 2015.

Enbridge's growth capital program is anchored by three major market access initiatives, supported by several mainline system expansion and regional infrastructure projects that are designed to ensure that there is sufficient capacity to support these new extensions. The three major market access initiatives are:

- the Gulf Coast Access Program;
- the Eastern Access Program; and
- the Light Oil Market Access Program.

In 2014, the Company made significant strides in its market access initiatives. In December 2014, Enbridge placed into service Flanagan South and Seaway Pipeline Twin, two key components of its Gulf Coast Access Program. Significant progress was also made in the Company's Eastern Access Program with the completion of the Line 6B replacement and expansion project in September 2014.

The $5.4 billion Gulf Coast Access Program includes Seaway Pipeline, Seaway Pipeline Twin, Flanagan South and elements of the Canadian Mainline and Lakehead System Mainline expansions and will increase access to refinery markets in the Gulf Coast. The $2.7 billion Eastern Access Program is expected to allow for greater access for crude oil into Chicago, further east into Toledo and ultimately into Ontario and Quebec. The Eastern Access Program includes the Company's Toledo pipeline expansion, Line 9 reversal, the existing Spearhead North pipeline expansion, Line 6B replacement and Line 5 expansion. Finally, the $6 billion Light Oil Market Access Program brings together a group of projects to support the increasing supply of light oil from Canada and the Bakken and also supplements the Eastern Access Program through the upsize of the Line 9B and Line 6B capacity expansion. The Light Oil Market Access Program also includes the Southern Access Extension Project (Southern Access Extension), Sandpiper, Canadian Mainline System Terminal Flexibility and Connectivity, twinning of the Spearhead

North pipeline (Spearhead North Twin) and Southern Access expansion included within the Lakehead System Mainline Expansion.

In 2014, Enbridge announced the $7.5 billion L3R Program, the largest growth capital project in the Company's history. The L3R Program will support the safety and operational reliability of the Company's mainline system as well as enhance the flexibility and optimize throughput. The Company also has approximately $6 billion in regional infrastructure projects under development, solidifying its position as the largest pipeline operator in the oil sands region of Alberta.

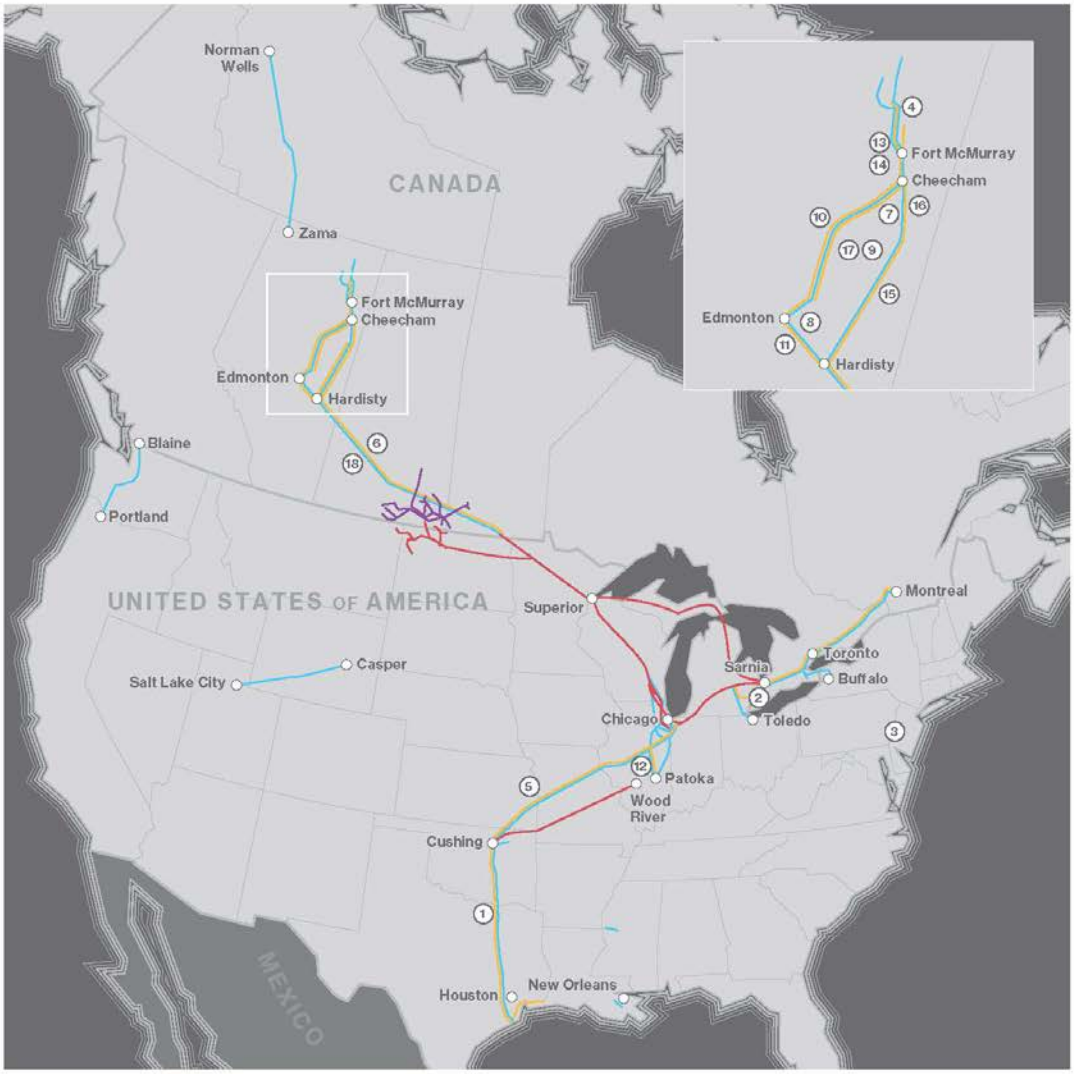
In keeping with the Company's strategic priority to develop new platforms to diversify and sustain long-term growth, Enbridge continued to expand its renewable energy generation capacity in 2014. With the purchase of additional interest in the Lac Alfred and Massif du Sud wind farms along with the acquisition of interests in two producing wind farms in the United States, Enbridge increased its net generating capacity to approximately 1,600 MW.

The following table 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$1.2 billion	2014	Complete
2. Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.6 billion	2013-2015 (in phases)	Substantially Complete
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$2.9 billion	US$2.8 billion	2014	Complete
6. Canadian Mainline Expansion	$0.7 billion	$0.5 billion	2015	Under Construction
7. Surmont Phase 2 Expansion	$0.3 billion	$0.2 billion	2014-2015 (in phases)	Under construction
8. Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.4 billion	2013-2015 (in phases)	Under construction
9. Sunday Creek Terminal Expansion	$0.2 billion	$0.2 billion	2015	Under construction
10. Woodland Pipeline Extension	$0.6 billion	$0.5 billion	2015	Under construction
11. Edmonton to Hardisty Expansion	$1.8 billion	$1.1 billion	2015	Under construction
12. Southern Access Extension	US$0.6 billion	US$0.2 billion	2015	Under-construction
13. AOC Hangingstone Lateral	$0.2 billion	No significant expenditures to date	2015	Under-construction
14. JACOS Hangingstone Project	$0.2 billion	No significant expenditures to date	2016	Pre-construction
15. Athabasca Pipeline Twinning	$1.2 billion	$1.1 billion	2017	Under-construction
16. Wood Buffalo Extension	$1.6 billion	$0.1 billion	2017	Pre-construction
17. Norlite Pipeline System[3]	$1.4 billion	No significant expenditures to date	2017	Pre-construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
18. Canadian Line 3 Replacement Program	$4.9 billion	$0.3 billion	2017	Pre-construction
GAS DISTRIBUTION				
19. Greater Toronto Area Project	$0.8 billion	$0.2 billion	2015	Under 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. Magic Valley and Wildcat Wind Farms	US$0.3 billion	US$0.3 billion	2014	Acquisition closed
23. Keechi Wind Project	US$0.2 billion	US$0.2 billion	2015	Complete
24. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-2015 (in phases)	Under construction
25. Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	2015	Under construction
26. Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
27. Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Under construction
28. Stampede Oil Pipeline	US$0.2 billion	No significant expenditures to date	2018	Pre-construction
SPONSORED INVESTMENTS				
29. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Complete
30. EEP - Eastern Access[4]	US$2.7 billion	US$2.1 billion	2013-2016 (in phases)	Under construction
31. EEP - Lakehead System Mainline Expansion[4]	US$2.3 billion	US$1.1 billion	2014-2017 (in phases)	Under construction
32. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	US$0.1 billion	2015	Under construction
33. EEP - Eaglebine Gathering	US$0.2 billion	No significant expenditures to date	2015-2016 (in phases)	Under construction
34. EEP - Sandpiper Project[5]	US$2.6 billion	US$0.4 billion	2017	Pre-construction
35. 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 December 31, 2014.*
3 *Enbridge will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.*
4 *The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.*
5 *Enbridge will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.*



Liquids Pipelines

1 Seaway Crude Pipeline System (Including Twinning and Extension)
2 Eastern Access (Line 9 Reversal and Expansion)
3 Eddystone Rail Project
4 Norealis Pipeline
5 Flanagan South Pipeline Project
6 Canadian Mainline Expansion
7 Surmont Phase 2 Expansion
8 Canadian Mainline System Terminal Flexibility and Connectivity
9 Sunday Creek Terminal Expansion
10 Woodland Pipeline Extension
11 Edmonton to Hardisty Expansion
12 Southern Access Extension
13 AOC Hangingstone Lateral
14 JACOS Hangingstone Project
15 Athabasca Pipeline Twinning
16. Wood Buffalo Extension
17 Norlite Pipeline System
18 Canadian Line 3 Replacement Program

Risks related to the development and completion of growth projects are described under *Risk Management and Financial Instruments – General Business Risks.*

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 January 2013, increasing capacity available to shippers from 150,000 bpd to up to approximately 400,000 bpd, depending on crude oil slate.

Twinning and Extension

Seaway Pipeline Twin was constructed in order to more than double the existing capacity of Seaway Pipeline to approximately 850,000 bpd and was mechanically completed in July 2014. Seaway Pipeline Twin was placed into service in December 2014 following the completion of 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 provides capacity of 750,000 bpd and was mechanically completed in August 2014 and placed into service in January 2015.

Including the acquisition of the initial 50% interest, Enbridge's total cost for Seaway Pipeline is 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 completed at an approximate cost of US$1.2 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 reversal of Line 9A, a reversal of Line 9B and expansion of Line 9 (together, Line 9) 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 Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Enbridge is also undertaking a reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in that province. The Line 9B reversal was initially expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity within Ontario and Quebec, resulting in the Line 9 capacity expansion project. The Line 9 capacity expansion will increase the annual capacity of Line 9 from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

The Line 9B Reversal and Line 9 Capacity Expansion Project was approved by the National Energy Board (NEB) in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B Reversal and Line 9 Capacity Expansion Project. On October 23, 2014, Enbridge responded to the NEB describing the Company's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB's order requiring approval, and the Company filed for a Leave to Open, which is a prerequisite to allowing the operation of the project. Subject to NEB approval for the Leave to Open application, Enbridge expects to place the Line 9B Reversal and Line 9 Capacity Expansion Project into service in the second quarter of 2015. In its February approval, the NEB also imposed additional obligations on Enbridge that direct the Company to take a "life-cycle" approach to water crossings and valves, requiring the Company performs ongoing analysis and rationale to ensure optimal protection of the area's water resources.

The conditions previously imposed by the NEB, including costs associated with additional NEB mandated integrity testing, increased the total expected cost of the projects to $0.7 billion, inclusive of costs related to the previously discussed Line 9A reversal. Enbridge has recently reached an agreement with shippers to recover a portion of the incremental cost of additional valves ordered by the NEB through a toll surcharge. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.6 billion.

On July 31, 2014, Enbridge filed an application for tolls for Line 9. After complaints from shippers on Line 9 were filed with the NEB with respect to the inclusion of mainline surcharges in the Line 9 toll, Enbridge requested that the NEB approve the tolls on an interim basis to allow for time to engage shippers in further discussions to attempt to resolve the outstanding issues. The NEB established interim tolls, which remain in effect and in late 2014, Enbridge and shippers filed letters with the NEB requesting that it establish a process to consider the issues. The NEB has set a written hearing with oral reply argument to be heard on May 28, 2015.

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. Eddystone Rail Project (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 transferred diluent into the Norealis Terminal in the fourth quarter of 2014 and receipt of blend product is expected in the second quarter of 2015.

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 was placed in-service on December 1, 2014 and the total cost of the project is now US$2.9 billion. Final expenditures will be incurred into 2015, with expenditures to date of approximately US$2.8 billion.

The Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint (the Complaint) for Declaratory and Injunctive Relief 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 United States' National Environmental Policy Act (NEPA). 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 Sierra Club filed an appeal to the United States Court of Appeals for the District of Columbia Circuit in mid-August 2014 and filed its opening brief on December 23, 2014. Enbridge and the Defendants filed their briefs on January 22, 2015. The Sierra Club's reply brief was filed on February 8, 2015 and an oral argument will be subsequently scheduled.

Canadian Mainline Expansion

Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases that involve the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was 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 $0.5 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 planned in two phases with the blended product system placed into service in November 2014 and the diluent system expected to be completed 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.

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 the second quarter of 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 $0.4 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 $0.2 billion and a targeted in-service date in the third quarter of 2015.

Woodland Pipeline Extension
The joint venture Woodland Pipeline Extension Project will extend the Woodland Pipeline south from Enbridge's Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 388-kilometre (241-mile), 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. After finalization of scope and a definitive cost estimate, Enbridge's share of the estimated capital cost of the project is approximately $0.6 billion, with expenditures incurred to date of approximately $0.5 billion. The project has a target in-service date of the third quarter of 2015.

Edmonton to Hardisty Expansion
The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project 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 by the fourth quarter of 2015, all at an expected total cost of approximately $1.8 billion. Expenditures incurred to date are approximately $1.1 billion.

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

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, which will provide capacity of 40,000 bpd and is expected to enter service in 2016, is now estimated to cost approximately $0.2 billion.

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 $1.1 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 overall system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system's overall western Canada export capacity.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in late 2017. Following the completion of a definitive cost estimate in the second quarter of 2014, the estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.3 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 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 began in January 2015 and completion of the project is expected in the fourth quarter of 2015 at a now estimated cost of approximately $0.8 billion, with expenditures to date of approximately $0.2 billion.

Gas Distribution

19 Greater Toronto Area Project

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Pipestone and Sexsmith Project

In 2012, the Company acquired from Encana Corporation (Encana) Pipestone and Sexsmith, which consist of certain sour gas gathering and compression facilities in the PRA region of northwest Alberta. 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, 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.

Magic Valley and Wildcat Wind Farms

In November 2014, Enbridge announced it had entered into an agreement with E.ON to purchase an 80% interest in a wind farm portfolio which included the 203-MW Magic Valley 1 wind farm located near Harligen, Texas and the 202-MW Wildcat 1 wind farm near Elwood, Indiana for approximately US$0.3 billion. Both wind farms are operational and were placed into service in 2012. Upon closing of the transaction on December 31, 2014, E.ON retained a 20% interest and remained the operator.

Gas Pipelines, Processing and Energy Services

20 Pipestone and Sexsmith Project
21 Blackspring Ridge Wind Project
22 Magic Valley and Wildcat Wind Farms
23 Keechi Wind Project
24 Walker Ridge Gas Gathering System
25 Big Foot Oil Pipeline
26 Aux Sable Extraction Plant Expansion
27 Heidelberg Lateral Pipeline
28 Stampede Oil Pipeline

Current Assets
Growth Opportunities
Wind Assets
Solar Assets

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, located in Jack County, Texas. The project was constructed by RES Americas under a fixed price, engineering, procurement and construction agreement at a total cost of approximately US$0.2 billion, and it entered service in January 2015. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year PPA with Microsoft Corporation.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the WRGGS to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 metres (7,000 feet), with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS was placed into service in December 2014 and the Big Foot Pipeline portion is expected to be placed into service in the third quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., Enbridge is constructing a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's undertaking of the WRGGS construction discussed above. Upon completion of the project, Enbridge will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.2 billion. As noted above, the Big Foot Pipeline is expected to enter service in the third quarter of 2015.

Aux Sable Extraction Plant Expansion

In 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, allow for effective management of Alliance Pipeline's downstream natural gas heat content and support additional production and sale of NGL products. The expansion is expected to be placed into service in 2016, with Enbridge's share of the project cost being approximately US$0.1 billion.

Heidelberg Oil Pipeline

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

Stampede Oil Pipeline

In January 2015, Enbridge announced that it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the planned Stampede development, which is operated by Hess, to an existing third-party pipeline system. The Stampede Pipeline, a 26-kilometre (16-mile), 18-inch diameter pipeline with capacity of approximately 100,000 bpd will originate in Green Canyon Block 468, approximately 350 kilometres (220 miles) southwest of New Orleans, Louisiana at an estimated depth of 1,200 metres (3,500 feet). After finalization of scope and a definitive cost estimate, Stampede Pipeline is now expected to be completed at an approximate cost of US$0.2 billion and is expected to be placed into service in 2018.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

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

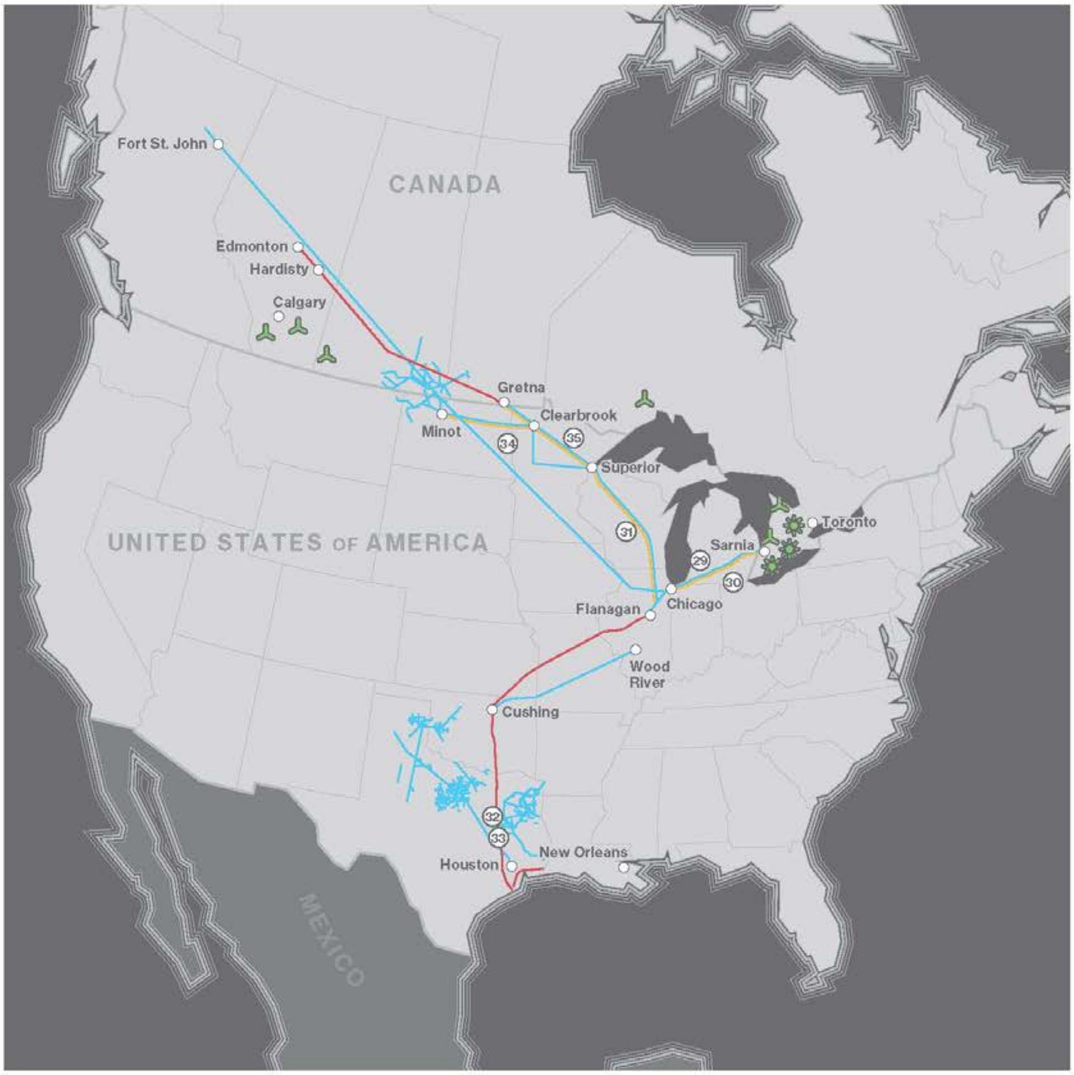
The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by EEP include an expansion of its Line 5 and expansions of the United States mainline 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$2.1 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%.



Sponsored Investments

29 EEP - Line 6B 75-Mile Replacement Program

30 EEP - Eastern Access

31 EEP - Lakehead System Mainline Expansion

32 EEP - Beckville Cryogenic Processing Facility

33 EEP - Eaglebine Gathering

34 EEP - Sandpiper Project

35 EEP - U.S. Line 3 Replacement Program

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

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase included increasing capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase of the expansion will increase capacity from 570,000 bpd to 800,000 bpd at an estimated capital cost of approximately US$0.2 billion. 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 anticipated that obtaining Federal regulatory approval will take longer than originally planned though approval is expected in the second half of 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.

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

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. Both phases of the Southern Access expansion require only the addition of pumping horsepower with no pipeline construction. The initial phase to increase the capacity from 400,000 bpd to 560,000 bpd was completed in August 2014 at an estimated capital cost of approximately US$0.2 billion. EEP also plans to undertake a further expansion of the Southern Access line between Superior and Flanagan to increase capacity from 560,000 bpd to 1,200,000 bpd and add crude oil tankage at new and existing sites. The pipeline expansion will be split into two tranches. The first tranche will expand the pipeline capacity to 800,000 bpd at an estimated capital cost of approximately US$0.4 billion and is expected to be in service in the second quarter of 2015. Additional tankage is expected to cost approximately US$0.4 billion and will be completed on various dates beginning in the second quarter of 2015 through early 2016. The second tranche, which remains subject to regulatory and other approvals, will expand the pipeline capacity to 1,200,000 bpd at an estimated capital cost of approximately US$0.4 billion. The Company is exploring with shippers the potential to delay the in-service date of the final tranche of the Line 61 expansion to align more closely with the currently anticipated in-service date for Sandpiper, which will drive the need for additional downstream capacity on the Lakehead System.

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

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$1.1 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 now expected to be placed into service in the second quarter of 2015 at an estimated cost of approximately US$0.1 billion. Expenditures incurred to date are approximately US$0.1 billion.

Eaglebine Gathering
In February 2015, EEP and MEP announced they are entering into the emerging Eaglebine shale play in East Texas through two transactions totalling approximately US$0.2 billion. EEP and MEP have commenced construction of a lateral and associated facilities that will create gathering capacity of over 50 mmcf/d for rich natural gas to be delivered from Eaglebine production areas to their complex of cryogenic processing facilities in East Texas. The initial facilities are projected to be placed into service by late 2015, with the lateral expected to be in service by mid-2016. MEP also executed an agreement with New Gulf Resources, LLC (NGR) to purchase NGR's midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation.

Sandpiper Project
As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper, which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline. Sandpiper is expected to cost approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.4 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, targeted for 2017 due to a longer than expected permitting process in the State of Minnesota.

A petition was filed with the Federal Energy Regulatory Commission (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 overall system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system's overall western Canada export capacity.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in late 2017 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.2 billion. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. EEP will recover the costs based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost of service methodology.

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 that have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

LIQUIDS PIPELINES
Northern Gateway Project
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.

In 2010, Northern Gateway submitted an application to the NEB and the Joint Review Panel (JRP) was established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act. The JRP had a broad mandate to assess the potential environmental effects of the project and to determine if development of Northern Gateway was in the public interest.

On December 19, 2013, the 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 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 and on December 17, 2014, the Federal Court issued a decision accepting the request by all parties to consolidate the nine applications into a single proceeding (the Application) and stated that delays in the hearing of the Application should be minimized. The Federal Court then set a schedule which would culminate with the filing of the Appellants' Memoranda of Fact and Law by May 22, 2015 and the Respondents' Memoranda by June 5, 2015. Based on this schedule, Northern Gateway expects that the hearing on the Application will occur in the fall of 2015. Depending on the outcome of these proceedings, which is anticipated for late 2015, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

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 assessed and refined by Northern Gateway and the potential shippers.

Subject to continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company 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. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the JRP website or the Northern Gateway website is incorporated by reference in, or otherwise part of this MD&A.***

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.

LIQUIDS PIPELINES

EARNINGS

	2014	2013	2012
(millions of Canadian dollars)			
Canadian Mainline	**500**	460	432
Regional Oil Sands System	**181**	170	110
Seaway and Flanagan South Pipelines	**74**	48	24
Southern Lights Pipeline	**49**	49	42
Spearhead Pipeline	**31**	31	37
Feeder Pipelines and Other	**23**	12	10
Adjusted earnings	**858**	770	655
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(370)**	(268)	42
Canadian Mainline - Line 9B costs incurred during reversal	**(8)**	-	-
Canadian Mainline - Line 9 tolling adjustment	**-**	-	6
Regional Oil Sands System - make-up rights adjustment	**6**	(13)	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(4)**	(56)	-
Regional Oil Sands System - leak insurance recoveries	**8**	-	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**-**	(37)	-
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**-**	31	-
Regional Oil Sands System - prior period adjustment	**-**	-	(6)
Seaway and Flanagan South Pipelines - make-up rights adjustment	**(25)**	-	-
Spearhead Pipeline - changes in unrealized derivative fair value gains	**1**	-	-
Feeder Pipelines and Other - make-up rights adjustment	**3**	-	-
Feeder Pipelines and Other - project development costs	**(6)**	-	-
Earnings attributable to common shareholders	**463**	427	697

Liquids Pipelines adjusted earnings were $858 million in 2014 compared with adjusted earnings of $770 million in 2013 and $655 million in 2012. The Company continued to realize growth on Canadian Mainline primarily from higher throughput from growing crude oil supply in western Canada and higher downstream refinery demand, as well as successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. These positive effects on Canadian Mainline were partially offset by a lower year-over-year average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll. New assets placed into service in Regional Oil Sands System and the completion of Flanagan South and Seaway Pipeline Twin also contributed to adjusted earnings growth.

Liquids Pipelines earnings were impacted by the following adjusting items:

- Canadian Mainline earnings for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage risk exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline earnings 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.
- Canadian Mainline earnings for 2012 included a Line 9 tolling adjustment related to services provided in prior periods.
- Regional Oil Sands System earnings for 2014 and 2013 included make-up rights adjustments to recognize revenue for certain long-term take-or-pay contracts ratably over the contract life. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. Generally, under such take-or-pay contracts, payments are received ratably over the life of the contract as capacity is provided, regardless of volumes shipped, and are non-

refundable. Should make-up rights be utilized in future periods, costs associated with such transportation service are typically passed through to shippers, such that little or no cost is borne by Enbridge. For the purposes of adjusted earnings, the Company reflects contributions from these contracts ratably over the life of the contract, consistent with contractual cash payments under the contract.

- Regional Oil Sands System earnings for 2014 and 2013 included charges, before insurance recoveries, related to the Line 37 crude oil release, which occurred in June 2013. Refer to *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release*.
- Regional Oil Sands System earnings for 2014 included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013. Refer to *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release*.
- 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 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.
- Regional Oil Sands System earnings for 2012 included a revenue recognition adjustment related to prior periods.
- Seaway and Flanagan South Pipelines earnings for 2014 included a make-up rights adjustment.
- Spearhead Pipeline earnings for 2014 included an unrealized fair value gain on derivative financial instruments.
- 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.

CANADIAN MAINLINE

The mainline system is comprised of Canadian Mainline and the Lakehead System (the portion of the mainline in the United States that is managed by Enbridge through its subsidiaries). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines, with a combined design operating capacity of approximately 2.6 million bpd, which cross the Canada/United States border near Gretna, Manitoba and Neche, North Dakota, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included in Canadian Mainline are two crude oil pipelines and one refined products pipeline located in eastern Canada.

Competitive Toll Settlement

Canadian Mainline tolls are governed by the 10-year settlement reached between Enbridge and shippers on its mainline system and approved by the NEB in 2011. The CTS, which took effect on July 1, 2011, covers local tolls to be charged for service on the mainline system (with the exception of Lines 8 and 9). Under the terms of the CTS, the initial Canadian Local Toll (CLT), applicable to deliveries within western Canada, was based on the 2011 Incentive Tolling Settlement (ITS) toll, subsequently adjusted by 75% of the Canada Gross Domestic Product at Market Price Index on July 1 of each year.

The CTS also provides for an IJT for crude oil shipments originating in Canada on the mainline system and delivered in the United States off the Lakehead System and into eastern Canada. The IJT, which is based on a fixed toll for the term of the settlement that was negotiated between Enbridge and shippers, will be adjusted annually by the same factor as the CLT.

In limited circumstances, the shippers or Enbridge may elect to renegotiate the toll. For shippers, the renegotiation rights exist in circumstances where Enbridge is seeking to recover from shippers, through tolls, potential increases to its cost structures. If a renegotiation of the toll is triggered, Enbridge and the shippers will meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the event.

Local tolls for service on the Lakehead System will not be affected by the CTS and will continue to be established pursuant to EEP's existing toll agreements. Under the terms of the IJT agreement between Enbridge and EEP, the Canadian Mainline's share of the IJT toll relating to pipeline transportation of a batch from any western Canada receipt point to the United States border is equal to the IJT toll applicable to that batch's United States delivery point less the Lakehead System's local toll to that delivery point. This amount is referred to as the Canadian Mainline IJT Residual Benchmark Toll.

The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System. Earnings under the CTS are subject to variability in volume throughput, as well as capital and operating costs and the United States dollar exchange rate. The Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues and commodity price risk resulting from exposure to crude oil and power prices.

Results of Operations
Canadian Mainline adjusted earnings were $500 million for the year ended December 31, 2014 compared with $460 million for the year ended December 31, 2013. 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. Other positive contributors to adjusted earnings included higher terminalling revenues, lower operating and administrative costs and lower income tax expense, which reflected current income taxes only and was lower due to higher available tax deductions.

Partially offsetting these positive impacts was a lower year-over-year average Canadian Mainline IJT Residual Benchmark Toll, with its impact especially prominent in the fourth quarter of 2014. 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. In the fourth quarter of 2014, the Canadian Mainline IJT Residual Benchmark Toll was US$1.53 per barrel compared with US$1.80 per barrel in the equivalent period of 2013. The decrease in the toll was a key contributor to lower adjusted earnings in the fourth quarter of 2014 compared with the same period of 2013. Also negatively impacting adjusted earnings were higher power costs associated with incremental throughput as well as higher depreciation from an increased asset base.

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.*

Canadian Mainline adjusted earnings for the year ended December 31, 2013 were $460 million compared with $432 million for the year ended December 31, 2012. The adjusted earnings increase was primarily driven by higher throughput from steady production from the oil sands in Alberta priced at levels that displaced other non-Canadian production from the midwest market and drove increased long-haul barrels on Canadian Mainline. Further volume growth on Canadian Mainline was limited towards the latter half of 2013 due to longer than expected refinery shutdowns and the delay in the start-up of a refinery conversion to heavy oil to the second quarter of 2014.

Partially offsetting the effect of increased throughput in 2013 was a lower Canadian Mainline IJT Residual Benchmark Toll effective April 1, 2013 compared with the corresponding 2012 period. Also negatively impacting 2013 adjusted earnings was an increase in power costs due to higher throughput, as well as higher depreciation and interest expense. Finally, income tax expense, which reflected current income taxes only, was lower due to higher available tax deductions from a larger asset base, including software.

Supplemental information on Canadian Mainline adjusted earnings for the years ended December 31, 2014, 2013 and 2012 is provided below.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Revenues	**1,465**	1,434	1,367
Expenses			
Operating and administrative	**381**	407	382
Power	**160**	122	112
Depreciation and amortization	**270**	244	219
	811	773	713
	654	661	654
Other income/(expense)	**11**	3	(4)
Interest expense	**(162)**	(162)	(131)
	503	502	519
Income taxes	**(3)**	(42)	(87)
Adjusted earnings	**500**	460	432
Effective United States to Canadian dollar exchange rate[1]	**1.016**	0.999	0.971

December 31,	**2014**	2013	2012
(United States dollars per barrel)			
IJT Benchmark Toll[2]	**$4.02**	$3.98	$3.94
Lakehead System Local Toll[3]	**$2.49**	$2.18	$1.85
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.53**	$1.80	$2.09

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.

Throughput Volume[1]

	Q1	Q2	Q3	Q4	Full Year
2014	**1,904**	**1,968**	**2,039**	**2,066**	**1,995**
2013	1,783	1,604	1,736	1,827	1,737
2012	1,687	1,659	1,617	1,622	1,646

1 Throughput, presented in thousands of barrels per day, represents mainline deliveries ex-Gretna, Manitoba, which is made up of United States and eastern Canada deliveries entering the mainline in western Canada.

Canadian Mainline revenues include the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Lines 8 and 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. Line 9B was idled in late 2013 and is being reversed and expanded as part of the Company's Eastern Access initiative. CTS revenues include transportation revenues, the largest component, as well as allowance oil and revenues from receipt and delivery charges. Transportation revenues include revenues for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which Canadian Mainline IJT residual tolls apply, and revenues for volumes delivered to other western Canada delivery points, to which the CLT applies. Despite the many factors that affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the United States dollar Canadian Mainline IJT Residual Benchmark Toll and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company currently utilizes derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues. The exact relationship between the primary determinants and actual Canadian Mainline revenues will vary somewhat from quarter to quarter but is expected to be relatively stable on average for a year, absent a systematic shift in receipt and delivery point mix or in crude oil type mix.

The largest components of operating and administrative expense are employee related costs, pipeline integrity, repairs and maintenance, rents and leases and property taxes. Operating and administrative costs are relatively insensitive to throughput volumes. The primary drivers of future increases in operating costs are expected to be normal escalation in wage rates, prices for purchased services, the addition of new facilities and more extensive integrity, ORM and maintenance programs.

Power, the most significant variable operating cost, is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements; however, the primary determinants of this cost are the power prices in various jurisdictions and throughput volume. The relationship of power consumption to throughput volume is expected to be roughly proportional over a moderate range of volumes. The Company currently utilizes derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of additions to property, plant and equipment due to new facilities, including integrity capital expenditures.

Canadian Mainline income taxes reflect current income taxes only. Under the CTS, the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to deferred income taxes is recognized as incurred. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

The preceding financial overview includes expectations regarding future events and operating conditions that the Company believes are reasonable based on currently available information; however, such statements are not guarantees of future performance and are subject to change.

REGIONAL OIL SANDS SYSTEM

Regional Oil Sands System includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline and two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located 70 kilometres (45 miles) south of Fort McMurray where the Waupisoo Pipeline initiates. The Regional Oil Sands System also includes the Wood Buffalo Pipeline, Woodland Pipeline and Norealis Pipeline which provide access for oil sands production from near Fort McMurray to the Cheecham Terminal as well as variety of other facilities such as the MacKay River, Christina Lake, Surmont and Long Lake laterals and related facilities.

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline. Built in 1999, it links the Athabasca oil sands in the Fort McMurray region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline’s capacity is 570,000 bpd, depending on the viscosity of crude being shipped, after completion of a pipeline expansion in December 2013. The Company has a long-term (30-year) take-or-pay contract with a major shipper on the Athabasca Pipeline that commenced in 1999. Revenues are recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered service in 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge’s Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline has a capacity of 415,000 bpd, depending on crude slate, and can ultimately be expanded to 600,000 bpd. Enbridge has a long-term (25-year) take-or-pay commitment with multiple shippers on the Waupisoo Pipeline who collectively have contracted for approximately three-quarters of the capacity.

Prior to December 10, 2012, Regional Oil Sands System included the Hardisty Storage Caverns which included four salt caverns totalling 3.5 million barrels of storage capacity. The capacity at the facilities is fully subscribed under long-term contracts that generate revenues from storage and terminalling fees. Along with the Hardisty Contract Terminals, the Hardisty Storage Caverns were transferred to the Fund in December 2012. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions* for details of the transfer.

Results of Operations

Regional Oil Sands System adjusted earnings for the year ended December 31, 2014 were $181 million compared with $170 million for the year ended December 31, 2013. Adjusted earnings growth was primarily driven by contributions from the Norealis Pipeline which was completed in April 2014, higher throughput on the Athabasca Pipeline and higher capital expansion fee revenue from the Waupisoo Pipeline. 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.

Adjusted earnings for the year ended December 31, 2013 were $170 million compared with $110 million for the year ended December 31, 2012. The increase in adjusted earnings was due to higher contracted volumes on the Athabasca Pipeline, higher capital expansion fees on the Waupisoo Pipeline and earnings from new assets placed into service in late 2012, including the Woodland and Wood Buffalo pipelines. Partially offsetting these earnings increases were higher operating and administrative costs, higher depreciation expense due to the commissioning of new assets and the absence of Hardisty Caverns earnings following the sale to the Fund in the fourth quarter of 2012.

Line 37 Crude Oil Release

On June 22, 2013, Enbridge reported a release of light synthetic crude oil on its Line 37 pipeline approximately two kilometres north of Enbridge's Cheecham Terminal. Line 37 connects facilities in the Long Lake area to the Cheecham Terminal. The Company estimated the volume of the release at approximately 1,300 barrels, caused by unusually high water levels in the region that triggered ground movement on the right-of-way. The oil released from Line 37 was recovered and on July 11, 2013, Line 37 returned to service at reduced operating pressure. Normal operating pressure was restored on Line 37 on July 29, 2013 after finalization of geotechnical analysis.

As a precaution, on June 22, 2013, the Company shut down the pipelines that share a corridor with Line 37, including the Athabasca, Waupisoo, Wood Buffalo and Woodland pipelines. Following extensive engineering and geotechnical analysis, all of the lines except Woodland Pipeline were returned to service by July 19, 2013. The Woodland Pipeline had been in the process of line fill at the time of the shutdown; line fill activities were completed in the third quarter of 2013.

For the years ended December 31, 2014 and 2013, the Company's earnings reflected remediation and long-term stabilization costs of approximately $4 million and $56 million after-tax and before insurance recoveries. Lost revenues associated with the shutdown of Line 37 and the pipelines sharing a corridor with Line 37 were minimal. At the time of the Line 37 crude oil release, Enbridge carried liability insurance for sudden and accidental pollution events, subject to a $10 million deductible.

The integrity and stability costs associated with remediating the impact of the high water levels were precautionary in nature and not covered by insurance. Enbridge expects to record receivables for amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery to be probable. For the year ended December 31, 2014, insurance recoveries of $8 million after-tax were recognized in connection with the Line 37 crude oil release. The cost estimates exclude any potential fines or penalties resulting from the ongoing investigation from a provincial governmental agency.

SEAWAY AND FLANAGAN SOUTH PIPELINES

Seaway and Flanagan South Pipelines include Enbridge's 50% interest in Seaway Pipeline and whole ownership of the recently completed Flanagan South.

Seaway Pipeline

In 2011, Enbridge acquired a 50% interest in the 1,078-kilometre (670-mile) Seaway Pipeline, including the 805-kilometre (500-mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast.

The flow direction of Seaway Pipeline was reversed in May 2012, enabling it to transport crude from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in January 2013, increasing capacity available to shippers from an initial 150,000 bpd to up to approximately 400,000 bpd, depending on crude oil slate. In late 2014, a second line was placed into service to more than double the existing capacity to 850,000 bpd. Seaway Pipeline also includes a 161-kilometre (100-mile) pipeline from the ECHO Terminal in Houston, Texas to the Port Arthur/Beaumont, Texas refining centre.

Flanagan South Pipeline

Flanagan South is a 950-kilometre (590-mile), 36-inch diameter interstate crude oil pipeline that originates at the Company's terminal at Flanagan, Illinois and terminates in Cushing, Oklahoma. Flanagan South and associated pumping stations were completed in the fourth quarter of 2014 and the majority of the pipeline parallels Spearhead Pipeline's right-of-way. Flanagan South has an initial design capacity of approximately 600,000 bpd; however, in its initial years, it is not expected to operate at its full design capacity.

Results of Operations

Seaway and Flanagan South Pipelines adjusted earnings for the year ended December 31, 2014 were $74 million compared with earnings of $48 million for the year ended December 31, 2013. Higher adjusted earnings reflected the incremental earnings associated with first oil received on Flanagan South and Seaway Pipeline Twin in December 2014. Also positively impacting adjusted earnings were higher average tolls on Seaway Pipeline. Partially offsetting the increased adjusted earnings were higher operating expense and financing costs from an increased asset base.

Seaway Pipeline earnings for the year ended December 31, 2013 were $48 million compared with earnings of $24 million for the year ended December 31, 2012. The higher contribution reflected a full year of operations and incremental available capacity on the pipeline in 2013 as noted above. Despite the increased capacity, actual throughput experienced in 2013 was curtailed due to constraints on third party takeaway facilities and during the latter part of the year due to loss of spot volume shipments as a result of a lower spread between crude oil prices at Cushing, Oklahoma and the Gulf Coast. Partially offsetting the earnings increase was higher financing costs and higher depreciation expense from an increased asset base.

Seaway Pipeline Regulatory Matter

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

The FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (ALJ) was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ's findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013, challenging the ALJ's decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise her decision accordingly. On May 9, 2014, the ALJ issued an initial decision on remand reiterating her previous findings and did not change her decision. Briefings have concluded and the full record was sent to the FERC for its final decision, which is still pending.

In relation to the original market based rate application, the FERC issued its decision rejecting Seaway Pipeline's application for market based rates in February 2014 and announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market based rate application consistent with the new policy. In December 2014, Seaway Pipeline filed a new market based rate application. No procedural schedule has been set.

SOUTHERN LIGHTS PIPELINE

The 180,000 bpd, 20-inch diameter Southern Lights Pipeline was placed into service on July 1, 2010, transporting diluent from Chicago, Illinois to Edmonton, Alberta. Enbridge receives tariff revenues under long-term contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus a ROE of 10%. Uncommitted volumes, up to a specified amount, generate tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers. As part of Enbridge's sponsored vehicle strategy, in November 2014, the Fund subscribed for and purchased 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, provide a defined cash flow stream to the Fund and a related financing cost to Southern Lights Pipeline. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions*.

Results of Operations

Southern Lights Pipeline earnings were $49 million for each of the years ended December 31, 2014 and 2013, respectively. Earnings were comparable between the two fiscal years, however, due to offsetting factors. Higher recovery of negotiated depreciation rates in 2014 transportation tolls were offset by higher interest expense associated with the issuance of Class A units to the Fund.

Southern Lights Pipeline earnings for the year ended December 31, 2013 were $49 million compared with $42 million for the year ended December 31, 2012. The increase in earnings reflected higher recovery of negotiated depreciation rates in 2013 transportation tolls.

SPEARHEAD PIPELINE

Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois a delivery point on the Lakehead System to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and an expansion was completed in May 2009, increasing capacity from 125,000 bpd to 193,300 bpd. Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead Pipeline. Both the initial committed shippers and expansion shippers were required to enter into 10-year shipping commitments at negotiated rates that were offered during the open season process. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.

Results of Operations

Adjusted earnings for Spearhead Pipeline were $31 million for each of the years ended December 31, 2014 and 2013, respectively. 2014 adjusted earnings reflected a combination of higher throughput and tolls, as well as lower pipeline integrity expenditures that were more prominent in 2013. These positive factors were offset by incremental power costs associated with higher throughput and by higher administrative expense.

Adjusted earnings for Spearhead Pipeline were $31 million for the year ended December 31, 2013 compared with $37 million for the year ended December 31, 2012. Higher contributions from increased throughput due to higher demand at Cushing, Oklahoma for further transportation on Seaway Pipeline to the Gulf Coast refining market were more than offset by higher operating expense, predominantly higher pipeline integrity expenditures. Operating margins were also compressed in 2013 due to an increase in power costs that resulted from transporting a mix of heavier crude.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company's 85% interest in Olympic Pipe Line Company (Olympic), the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. It also includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta, interests in a number of liquids pipelines in the United States, including the Toledo Pipeline, which connects with the EEP mainline at Stockbridge, Michigan, and business development costs related to Liquids Pipelines activities.

Prior to December 10, 2012, Feeder Pipelines and Other also included the Hardisty Contract Terminals, which is comprised of 19 tanks with a working capacity of approximately 7.5 million barrels of storage capacity. Along with the Hardisty Storage Caverns, the Hardisty Contract Terminals were transferred to the Fund in December 2012. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions* for details of the transfer.

Results of Operations

Feeder Pipelines and Other adjusted earnings were $23 million compared with $12 million for the year ended December 31, 2013. The increase in adjusted earnings in Feeder Pipelines and Other reflected higher tolls and throughput on the Toledo Pipeline, incremental earnings from Eddystone completed in April 2014, higher tankage revenues and lower business development costs not eligible for capitalization. Partially offsetting the increase in adjusted earnings were lower average tolls on Olympic.

Feeder Pipelines and Other adjusted earnings were $12 million for the year ended December 31, 2013 compared with $10 million for the year ended December 31, 2012. The earnings increase was primarily attributable to higher volumes and tolls on Olympic.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Enbridge is exposed to throughput risk under the CTS on the Canadian Mainline and under certain tolling agreements applicable to other Liquids Pipelines assets. A decrease in volumes transported can directly and adversely affect revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of Enbridge's assets.

Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions outside of Enbridge's control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on Enbridge's pipelines. However, the long-term outlook for Canadian crude oil production indicates a growing source of potential supply of crude oil.

Under certain contracts, committed shippers are provided with relief from their take-or-pay payment obligations to the extent such shippers are unable to ship committed volumes on a pipeline solely as a result of Canadian Mainline apportionment.

Enbridge seeks to mitigate utilization risks within its control. The market access expansion initiatives, which have had components placed into service over the past several years, and those currently under development have and are expected to reduce capacity bottlenecks and enhance access to markets for customers. Liquids Pipelines also seeks to optimize capacity and throughput on its existing assets by working with the shipper community to enhance scheduling efficiency and communications as well as makes continuous improvements to scheduling models and timelines to maximize throughput. Further to the day-to-day improvements sought by the Company, in 2014, Enbridge and EEP announced the $7.5 billion L3R Program. Expected to be completed in late 2017, this project will not increase the overall capacity of the mainline system, but will instead support the safety and operational reliability of the overall system and enhance the flexibility on the mainline system allowing the Company to further optimize throughput. Throughput risk is partially mitigated by provisions in the CTS agreement, which allow Enbridge to adjust the applicable L3R Program surcharge if volumes fall below defined thresholds or to negotiate an amendment to the agreement in the event certain minimum threshold volumes are not met.

Operational and Economic Regulation

Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of Liquids Pipelines assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on the Company's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Company.

The Company's liquids pipelines also face economic regulatory risk. Broadly defined, economic regulation risk is the risk regulators or other government entities change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The Canadian Mainline and other liquids pipelines are subject to the actions of various regulators, including the NEB and the FERC, with respect to the tariffs and tolls of those operations. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on the Company's revenues and earnings. Delays in regulatory approvals could result in cost escalations and constructions delays, which also negatively impact the Company's operations.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of the segment's assets. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls on new and existing pipelines. However, despite the best efforts of the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Competition

Competition may result in a reduction in demand for the Company's services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets.

Other competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada and the United States represent competition to the Company's liquids pipelines network. Competition also arises from proposed pipelines that seek to access markets currently served by the Company's liquids pipelines, such as proposed projects to the Gulf Coast or eastern markets. Competition also exists from proposed projects enhancing infrastructure in the Alberta regional oil sands market. Additionally, volatile crude price differentials and insufficient pipeline capacity on either Enbridge or other competitor pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently serviced by pipelines.

The Company believes that its liquids pipelines continue to provide attractive options to producers in the WCSB due to its competitive tolls and flexibility through its multiple delivery and storage points. Enbridge's current complement of growth projects to expand market access and to enhance capacity on the Company's pipeline system combined with the Company's commitment to project execution is expected to further provide shippers reliable and long-term competitive solutions for oil transportation. The Company's existing right-of-way for the Canadian Mainline also provides a competitive advantage as it can be difficult and costly to obtain rights of way for new pipelines traversing new areas. The Company also employs long-term agreements with shippers, which also mitigate competition risk by ensuring consistent supply to the Company's liquids pipelines network.

Foreign Exchange and Interest Rate Risk

The CTS agreement for the Canadian Mainline exposes the Company to risks related to movements in foreign exchange rates and interest rates. Foreign exchange risk arises as the Company's IJT under the CTS is charged in United States dollars. These risks have been substantially managed through the Company's hedging program by using financial contracts to fix the prices of United States dollars and interest rates. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, the Company's earnings are exposed to associated changes in the mark-to-market value of these contracts.

GAS DISTRIBUTION

EARNINGS

	2014	2013	2012
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc. (EGD)	**158**	156	149
Other Gas Distribution and Storage	**19**	20	27
Adjusted earnings	**177**	176	176
EGD - (warmer)/colder than normal weather	**36**	9	(23)
EGD - gas transportation costs out-of-period adjustment	**-**	(56)	-
EGD - tax rate changes	**-**	-	(9)
EGD - recognition of regulatory asset	**-**	-	63
Earnings attributable to common shareholders	**213**	129	207

Adjusted earnings from Gas Distribution were $177 million for the year ended December 31, 2014 compared with $176 million for each of the years ended December 31, 2013 and 2012. EGD 2014 results reflect the approval of its five-year customized IR Plan by the OEB. EGD adjusted earnings increased slightly due to customer growth and lower depreciation expense under a new approach for determining depreciation and future removal and site restoration reserves. Partially offsetting these positive factors were lower rates and the resumption of the earnings sharing mechanism.

Gas Distribution earnings were impacted by the following adjusting items:

- EGD earnings for each period were adjusted to reflect the impact of weather.
- EGD earnings for 2013 reflected an out-of-period correction to gas transportation costs that had previously been deferred.
- EGD earnings for 2012 reflected the impact of unfavourable tax rate changes on deferred income tax liabilities.
- EGD earnings for 2012 included the recognition of a regulatory asset related to recovery of other postretirement benefit obligations (OPEB) costs pursuant to an OEB rate order. Refer to *Gas Distribution – Enbridge Gas Distribution Inc. – Incentive Rate Plan.*

ENBRIDGE GAS DISTRIBUTION INC.

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves over two million customers in central and eastern Ontario and parts of northern New York State. EGD's utility operations are regulated by the OEB and the New York State Public Service Commission.

Incentive Rate Plan

In July 2013, EGD filed an application with the OEB for the setting of rates through a customized IR Plan for the period of 2014 through to 2018. EGD continued to apply 2013 rates in 2014, pursuant to a November 2013 interim rate order, until a final rate order for 2014 rates was issued by the OEB. A decision from the OEB was provided on July 17, 2014, with a subsequent decision and rate order provided on August 22, 2014. The OEB approved the customized IR Plan, with modifications, for 2014 through 2018 inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE. The OEB's decision provides the methodology for establishing rates for the distribution of natural gas for a five-year period from 2014 through 2018. The customized IR Plan provides EGD the framework needed for anticipated investment in its Ontario natural gas distribution system and incentivizes the Company to implement productivity efficiencies that benefit customers.

The OEB approved final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism, with an effective date of January 1, 2014. Within annual rate proceedings for 2015 through 2018, the customized IR Plan requires allowed revenues, and corresponding rates, to be updated annually for select items including the rate of return to be earned on the equity component of its rate base. The annual updates reduce forecast risk and ensure rates reflect current market conditions. The OEB also approved the adoption of a new approach for determining net salvage percentages to be included within EGD's approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves.

In order to align the interest of customers with the Company's shareholders, an earnings sharing mechanism was included as part of the customized IR Plan, whereby any return over the allowed rate of return for a given year under the customized IR Plan is to be shared equally with customers. For the year ended December 31, 2014, EGD recognized $12 million as a return of revenues to customers in relation to the earnings sharing mechanism.

EGD's 2013 rates were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed ROE. The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories. There was no earnings sharing mechanism under the 2013 Settlement. The 2013 Settlement allowed EGD to recognize revenue and a corresponding regulatory asset relating to OPEB as it established the right to recover previous OPEB costs of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

Prior to 2013, EGD operated under a five-year revenue cap IR mechanism, with rates calculated using a formula approved by the OEB based on revenue per customer. Under this mechanism, the Company was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis. For the year ended December 31, 2012, EGD recognized $10 million as a return of revenues to customers in relation to the earnings sharing mechanism.

Results of Operations

EGD adjusted earnings for the year ended December 31, 2014 were $158 million compared with $156 million for the year ended December 31, 2013. EGD adjusted earnings reflected the impact of the OEB decision on EGD's customized IR Plan which was approved with modifications by the OEB in July 2014. EGD operated the first half of 2014 under OEB approved interim distribution rates. On August 22, 2014, an OEB Rate Order under the customized IR Plan approved the final rates with an effective date of January 1, 2014.

The slight increase in EGD year-over-year adjusted earnings reflected customer growth, lower employee related and other costs and the impact of the approved customized IR Plan. The customized IR Plan approved a new approach for determining depreciation and future removal and site restoration reserves, which resulted in a lower depreciation expense for the year ended December 31, 2014. These positive effects were partially offset by reduced rates and the resumption of the earnings sharing mechanism under the customized IR Plan, as well as lower shared savings mechanism revenues.

EGD adjusted earnings for the year ended December 31, 2013 were $156 million compared with $149 million for the year ended December 31, 2012. Higher adjusted earnings reflected customer growth, the absence of the earnings sharing under the 2013 Settlement and higher shared savings mechanism revenues, which resulted from exceeding targets on delivery of energy efficiency programs. Also favourably impacting adjusted earnings was the recovery of pension costs allowed to be passed on to customers under the 2013 Settlement, whereas previously these costs were partially disallowed under the 2012 IR mechanism. Partially offsetting the favourable adjusted earnings increase was lower revenues from non-regulated operations.

OTHER GAS DISTRIBUTION AND STORAGE
Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being Enbridge Gas New Brunswick Inc. (EGNB) which is wholly-owned and operated by the Company. EGNB owns the natural gas distribution franchise in the province of New Brunswick and has approximately 11,000 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

Results of Operations
Other Gas Distribution and Storage earnings were $19 million for the year ended December 31, 2014 compared with $20 million for the year ended December 31, 2013. Lower earnings included a loss from EGNB related to a contract, which expired in October 2014, 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. Higher distribution volumes and higher rates that became effective in May 2014 partially offset the decreased earnings in EGNB.

Other Gas Distribution and Storage earnings were $20 million for the year ended December 31, 2013 compared with $27 million for the year ended December 31, 2012. The decrease in earnings reflected lower rates from a revised rate setting methodology that became effective October 1, 2012 in EGNB. The earnings decrease was partially offset by new rates that became effective August 1, 2013 which allowed EGNB to fully recover its revenue requirement and drove higher earnings in the second half of 2013.

Enbridge Gas New Brunswick Inc. – Regulatory Matters
On December 9, 2011, the Government of New Brunswick tabled and then subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permitted the government to implement new regulations that could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amended rate setting methodology and specific conditions outlined therein, EGNB no longer met the criteria for the continuation of rate-regulated accounting. As a result, the Company eliminated from its Consolidated Statements of Financial Position a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million. As the final rates and tariffs regulation published on April 16, 2012 provided further evidence of a condition that existed on December 31, 2011, the charge totalling $262 million, after-tax, was reflected as a subsequent event in the Company's Consolidated Financial Statements for the year ended December 31, 2011 presented in accordance with U.S. GAAP and filed in May 2012.

The Company commenced legal proceedings against the Government of New Brunswick, seeking damages for breach of contract, in April 2012. The Company also commenced a separate application to the New Brunswick Court of Queen's Bench to quash the Government's rates and tariffs regulation in May 2012. The Company's application was initially dismissed, but on appeal it was ultimately successful, in part. The Court of Appeal ruled that the part of 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. As a result of this outcome, EGNB applied on June 14, 2013 to the EUB for new rates, effective July 1, 2013, for commercial and industrial customers. On July 26, 2013, the EUB granted EGNB's application for new rates, but with an effective date of August 1, 2013. The EUB's decision enabled EGNB to fully recover its revenue requirement from August 1, 2013 until the next rate period. EGNB's 2014 rate application was approved in April 2014 by the EUB and its application for 2015 rates was approved in December 2014.

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, as discussed above.

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.

BUSINESS RISKS

The risks identified below are specific to Gas Distribution business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Economic Regulation

The utility operations of Gas Distribution are regulated by the OEB and EUB among others. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which Gas Distribution operates. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

The Company seeks to mitigate economic regulation risk by maintaining regular and transparent communication with regulators and intervenors on rate negotiations. The terms of rate negotiations are also reviewed by the Company's legal, regulatory and finance teams. The approval of the five-year customized IR Plan also provides a level of stability by having a longer-term agreement with the OEB which allows EGD to recover its expected capital investments under the agreement, as well as an opportunity to earn above the OEB allowed ROE. Under the customized IR Plan, EGD is permitted to recover, with OEB approval, certain costs that were beyond management control, but that were necessary for the maintenance of its services. The customized IR Plan also includes a mechanism to reassess the customized IR Plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the customized IR Plan. The above noted terms set out in the settlement agreement mitigate the Company's risk to factors beyond management's control.

Natural Gas Cost Risk

EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB for inclusion in distribution rates. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and may request interim rate relief to recover or refund the natural gas cost differential. While the cost of natural gas does not impact EGD's earnings, it does affect the amount of EGD's investment in gas in storage. The OEB also determines the timing of payment or collection from customers which can have an impact on EGD's working capital during the period in which costs are expected to be recovered.

EGNB is also subject to natural gas cost risk as increases in natural gas prices that cannot be charged to customers could negatively impact earnings.

Volume Risk
Since customers are billed on a volumetric basis, EGD's ability to collect its total revenue requirement (the cost of providing service) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions from all market sectors are important as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. EGNB is also subject to volume risk as the impact of weather conditions on demand for natural gas could result in earnings fluctuations.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

EARNINGS

	2014	2013	2012
(millions of Canadian dollars)			
Aux Sable	**28**	49	68
Energy Services	**35**	75	40
Alliance Pipeline US	**41**	43	39
Vector Pipeline	**15**	22	22
Canadian Midstream	**23**	12	-
Enbridge Offshore Pipelines (Offshore)	**(2)**	(2)	(3)
Other	**(4)**	4	10
Adjusted earnings	**136**	203	176
Aux Sable - changes in unrealized derivative fair value gains	**-**	-	10
Energy Services - changes in unrealized derivative fair value gains/(loss)	**424**	(206)	(537)
Offshore - gain on sale of non-core assets	**57**	-	-
Offshore - asset impairment loss	**-**	-	(105)
Other - changes in unrealized derivative fair value loss	**-**	(61)	-
Earnings/(loss) attributable to common shareholders	**617**	(64)	(456)

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $136 million for the year ended December 31, 2014 compared with $203 million for the year ended December 31, 2013 and $176 million for the year ended December 31, 2012. Unfavourable market conditions in Aux Sable and Energy Services contributed to lower adjusted earnings in 2014. Lower fractionation margins and lower volumes at upstream processing plants contributed to lower Aux Sable earnings over the past two years. In Energy Services, narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges, drove lower adjusted earnings after a very strong 2013 fiscal year. Partially offsetting the decrease were positive contributions from the Company's Canadian midstream assets and new renewable energy investments.

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

- Aux Sable earnings for 2012 period reflected changes in the fair value of unrealized derivative financial instruments related to the Company's forward gas processing risk management position.
- Energy Services earnings/(loss) for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.
- Energy Services adjusted earnings for 2014 excluded a realized loss of $117 million incurred 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 derivative contracts intended to hedge forecasted Energy Services transactions which did not occur.
- Offshore earnings for 2014 included a gain from the disposal of non-core assets.
- Offshore loss for 2012 was impacted by an asset impairment loss related to certain of its assets, predominantly located within the Stingray and Garden Banks corridors. Refer to *Gas Pipelines, Processing and Energy Services – Enbridge Offshore Pipelines – Asset Impairment.*
- Other loss for 2013 reflected changes in unrealized fair value loss on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from Blackspring Ridge.

AUX SABLE

Enbridge owns a 42.7% interest in Aux Sable US and a 50% interest in Aux Sable Canada (together, Aux Sable). Aux Sable US owns and operates a NGL extraction and fractionation plant outside Chicago, Illinois near the terminus of Alliance Pipeline. The plant extracts NGL from the liquids-rich natural gas transported on Alliance Pipeline as necessary for Alliance Pipeline to meet gas quality specifications of downstream transmission and distribution companies and to take advantage of positive fractionation spreads.

Aux Sable US sells its NGL production to a single counterparty under a long-term contract. Aux Sable receives a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, Aux Sable is compensated for all operating, maintenance and capital costs associated with its facilities subject to certain limits on capital costs. The counterparty supplies all make-up gas and fuel gas requirements of the Aux Sable plant. The contract is for an initial term of 20 years, expiring March 31, 2026, and may be extended by mutual agreement for 10-year terms.

Aux Sable also owns and operates facilities upstream of Alliance Pipeline that deliver liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned by Aux Sable US and the Septimus Gas Plant and the Septimus Pipeline in the Montney area of British Columbia, owned by Aux Sable Canada.

Aux Sable Canada has contracted capacity of the Septimus Pipeline and the Septimus Gas Plant to a producer under a 10-year take-or-pay contract which provides for a return on and of invested capital. Actual operating costs are recovered from the producer. In 2014, the majority of capacity at the Palermo

Gas Plant and the Prairie Rose Pipeline was contracted to producers under take-or-pay contracts. Several producers' contract commitments will decline over the next few years while certain producer contract commitments will continue through 2020 under long-term take or pay contracts or with life-of-lease reserve dedication. Additional revenues are earned by Aux Sable based on a sharing of available NGL margin with producers.

In September 2014, Aux Sable received a Notice of Violation (NOV) from the United States Environmental Protection Agency (EPA) for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the NOV, Aux Sable discovered what it believes to be additional exceedance of currently permitted limits for Volatile Organic Material. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact, if any, which might result from discussions with the EPA.

Results of Operations

Aux Sable earnings for the year ended December 31, 2014 were $28 million compared with $49 million for the year ended December 31, 2013. Aux Sable earnings reflected lower fractionation margins which decreased contributions from the upside sharing mechanism, partially offset by an increase in propane volumes produced at the Channahon Plant. Lower volumes at upstream processing plants and higher administrative expense also had a negative impact on Aux Sable earnings.

Aux Sable adjusted earnings for the year ended December 31, 2013 were $49 million compared with adjusted earnings of $68 million for the year ended December 31, 2012. The decrease in adjusted earnings was mainly attributable to lower fractionation margins and lower ethane processing volumes due to ethane rejections. Lower fractionation margins resulted in a decrease in contributions from the upside sharing mechanism in Aux Sable's production sales agreement compared with the prior year.

Aux Sable Feedstock Supply

Aux Sable extracts and sells NGL from natural gas shipped on Alliance Pipeline under current long-term transportation contracts and also secures NGL feedstock for its Channahon plant through rich-gas premium contracts with producers. Commencing December 1, 2015, when gas transportation services under Alliance Pipeline's proposed new service offerings are scheduled to start, Aux Sable has contracted for additional liquids-rich gas supplies with producers. Aux Sable producers have entered into a variety of precedent transportation agreements with Alliance Pipeline for its new transportation services. Aux Sable has entered into certain gas purchase and sales contracts with several counterparties at Alliance Pipeline's proposed Alberta Transfer Point. Any commodity price exposure created from Aux Sable's gas purchase and resale business is closely monitored and must comply with its formal risk management policies that are consistent with the Company's risk management practices. For further details on Alliance Pipeline Recontracting, refer to *Sponsored Investments – Enbridge Income Fund – Alliance Pipeline Recontracting.*

Business Risks

The risks identified below are specific to Aux Sable. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Commodity Price Risk

Aux Sable's margin earned through the upside sharing mechanism is subject to commodity price risk arising from the price differential between the cost of natural gas and margins achieved from the sale of extracted NGL after the fractionation process. These risks may be mitigated by Aux Sable or through the Company's risk management activities.

Asset Utilization

A decrease in gas volumes or a decrease in the NGL content of the gas stream delivered by Alliance Pipeline to the Aux Sable plant can directly and adversely affect the margin earned through the upside sharing mechanism. Alliance Pipeline is well-positioned to deliver incremental liquids-rich gas production from new developments in the Montney, Duvernay and Bakken regions, thereby mitigating volume risk. In addition, Aux Sable attracts liquids-rich gas to Alliance Pipeline through inducement and rich-gas premium contracts with producers.

ENERGY SERVICES

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy. This business transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company focused on capturing value from quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Tidal Energy also provides natural gas marketing services, including marketing natural gas to optimize commitments on certain natural gas pipelines. Additionally, Tidal Energy provides natural gas supply, transportation, balancing and storage for third parties, leveraging its natural gas marketing expertise and access to transportation capacity.

Any commodity price exposure created from Tidal Energy's physical business is closely monitored and must comply with the Company's formal risk management policies. To the extent transportation costs and other fees exceed the basis (location) differential, earnings will be negatively affected.

Results of Operations

Energy Services adjusted earnings were $35 million for the year ended December 31, 2014 compared with $75 million for the year ended December 31, 2013. Adjusted earnings decreased in 2014 compared with a very strong 2013 due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, combined with associated unrecovered demand charges. Additionally, the 2014 adjusted earnings reflected losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second and fourth quarters 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 adjusted earnings were more favourable conditions in certain markets in the fourth quarter of 2014 that gave rise to wider location and crude grade differentials and enabled Energy Services to capture more profitable margin and tank management arbitrage opportunities. Due in large part to the continued positive effects of these arbitrage opportunities, Energy Services 2014 fourth quarter adjusted earnings increased compared with the equivalent 2013 period which helped to partially offset the decrease in adjusted earnings experienced during the first nine months of the year. Also positively contributing to adjusted earnings were favourable natural gas location differentials caused by abnormal winter weather conditions during the first quarter of 2014. Energy Services adjusted earnings are dependent on market conditions and results achieved in one period may not be indicative of results achieved in future periods.

Energy Services adjusted earnings were $75 million for the year ended December 31, 2013 compared with $40 million for the year ended December 31, 2012. The increase in adjusted earnings reflected wide location and crude grade differentials which gave rise to a greater number of and more profitable margin opportunities during the first half of 2013. These physical marketing opportunities began to diminish in the third quarter and culminated in a fourth quarter adjusted loss for Energy Services. Market conditions contributing to the fourth quarter adjusted loss included physical constraints which limited physical movement of barrels, such as pipeline apportionment and refinery outages, narrowing location spreads among markets physically accessed by Tidal Energy's committed transportation capacity and narrowing grade differentials which limited tank management opportunities. Although profitability declined in most lines of business, the loss in the fourth quarter of 2013 primarily related to losses realized on financial contracts intended to hedge the value of committed physical transportation capacity, but which were not effective in doing so in the last three months of the year.

Business Risks
The risks identified below are specific to Energy Services. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Commodity Price Risk
Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Volatility in commodity prices and changing marketing conditions could limit margin opportunities. Furthermore, commodity prices could have negative earnings impacts if the cost of the commodity is greater than resale prices achieved by the Company. Energy Services activities are conducted in compliance with and under the oversight of the Company's formal risk management policies, including the implementation of hedging programs to manage exposure to changes in commodity prices, inclusive of exposures inherent within forecasted transactions. To the extent a forecasted transaction does not occur as anticipated, hedge ineffectiveness or termination may result. Certain financial contracts may not qualify for cash flow hedge accounting; therefore, the Company's earnings are exposed to associated changes in the mark-to-market value of these contracts.

Competition
Energy Services earnings are generated from arbitrage opportunities which, by their nature, can be replicated by other competitors. An increase in market participants looking for similar arbitrage opportunities could have an impact on the Company's earnings. The Company's efforts to mitigate competition risk includes diversification of its marketing business by trading at the majority of major hubs in North America and establishing long-term relationships with clients.

ALLIANCE PIPELINE US
Alliance Pipeline, which includes both the Canadian (Alliance Pipeline Canada) and United States (Alliance Pipeline US) portions of the pipeline system, consists of approximately 3,000 kilometres (1,864 miles) of integrated, high-pressure natural gas transmission pipeline and approximately 860 kilometres (534 miles) of lateral pipelines and related infrastructure. Alliance Pipeline transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have firm service shipping contract capacity to deliver 1.466 billion cubic feet per day (bcf/d) and 1.325 bcf/d, respectively. Alliance Pipeline connects with the Aux Sable NGL extraction and fractionation plant. Natural gas transported on Alliance Pipeline downstream of the Aux Sable plant can be delivered to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and eastern United States and eastern Canada. In September 2013, Alliance US completed construction of the Tioga Lateral Pipeline (Tioga Lateral) which facilitates delivery of natural gas from the Tioga field processing plant in the Bakken to downstream markets.

In November 2014, Enbridge's 50% ownership of the Alliance Pipeline US was transferred to the Fund with earnings contributions from Alliance Pipeline US prospectively reflected within the Sponsored Investments section effective November 7, 2014. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions* for details of the transfer. Effective November 7, 2014 the Fund owns 50% of Alliance Pipeline US along with its previous 50% ownership of Alliance Pipeline Canada. For business risks specific to the Alliance Pipeline refer to *Sponsored Investments – Enbridge Income Fund – Business Risks – Alliance Pipeline.*

Results of Operations
Alliance Pipeline US earnings were $41 million for the year ended December 31, 2014 compared with earnings of $43 million for the year ended December 31, 2013. The decrease in Alliance Pipeline US earnings reflected the impact of the transfer of Alliance Pipeline US to the Fund in November 2014 and the corresponding absence of earnings. Prior to November 7, 2014, the date of the transfer, Alliance Pipeline US earnings increased compared with the equivalent 2013 period and reflected an increase in depreciation expense recovered in tolls, as well as earnings from the Tioga Lateral which was placed into service in September 2013.

Alliance Pipeline US earnings were $43 million for the year ended December 31, 2013 compared with earnings of $39 million for the year ended December 31, 2012. The increase in earnings in 2013 compared with 2012 reflected an increase in depreciation expense recovered through tolls and earnings related to the Tioga Lateral.

VECTOR PIPELINE

Vector, which includes both the Canadian and United States portions of the pipeline system, consists of 560 kilometres (348 miles) of mainline natural gas transmission pipeline between the Chicago, Illinois hub and a storage complex at Dawn, Ontario. Vector's primary sources of supply are through interconnections with Alliance Pipeline and the Northern Border Pipeline in Joliet, Illinois. Vector has the capacity to deliver a nominal 1.3 bcf/d and is operating at or near capacity. The Company provides operating services to and holds a 60% joint venture interest in Vector.

Results of Operations

Vector earnings were $15 million for the year ended December 31, 2014 compared with earnings of $22 million for the years ended December 31, 2013 and 2012. The year-over-year decrease in Vector earnings reflected lower depreciation expense recognized in tolls, partially offset by increased demand for natural gas due to abnormal winter weather conditions experienced in the first quarter of 2014.

Transportation Contracts

The total long haul capacity of Vector is approximately 94% committed through November 2015. Approximately 55% of the long haul capacity is committed through firm negotiated rate transportation contracts with shippers and approved by the FERC, while the remaining committed capacity is sold at market rates.

In December 2014, shippers under negotiated rate transportation contracts which represent 20% of the system's long haul capacity elected to extend their commitments through December 1, 2017 and preserve the option to extend their contracts on an annual basis. Vector is entitled to additional compensation from negotiated rate transportation shippers that terminate their contracts prior to the November 30, 2020 expiry date.

Vector has recently signed precedent agreements with both the proposed NEXUS pipeline and Energy Transfer Partners L.P.'s Rover Pipeline project, to provide transportation service to the Dawn natural gas market hub. Both projects are in the development stage and are subject to FERC approval.

Transportation service is provided through a number of different forms of service agreements, such as Firm Transportation Service and Interruptible Transportation Service. Vector is an interstate natural gas pipeline with FERC and NEB approved tariffs that establish the rates, terms and conditions governing its service to customers. On the United States portion of Vector, maximum tariff rates are determined using a cost of service methodology and maximum tariff changes may only be implemented upon approval by the FERC. For 2014, the FERC-approved maximum tariff rates included an underlying weighted average after-tax ROE component of 11.2%. On the Canadian portion, Vector is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2014, maximum tolls include an ROE component of 10.5% after-tax.

Business Risks

The risks identified below are specific to Vector. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*. For risks specific to Alliance Pipeline refer to *Sponsored Investments – Enbridge Income Fund – Business Risks – Alliance Pipeline.*

Asset Utilization

Currently, natural gas pipeline capacity out of the WCSB exceeds supply, due to the low price of natural gas and increased production from new shale gas developments. Vector has been minimally impacted by this excess supply environment to date mainly because of long-term capacity contracts extending primarily to November 2015. However, excess supply and depressed natural gas prices could lead to a reduction or deferral of investment in upstream gas development and could negatively impact re-contracting beyond this term until further development of Marcellus/Utica sourced gas. Vector has entered into precedent agreements to provide transport service to two proposed greenfield pipeline projects that will extend back to the Marcellus/Utica supply basin. These arrangements, scheduled to commence in 2017, will effectively fill all available capacity from current contract roll-offs scheduled through 2019.

Competition

Vector faces competition for pipeline transportation services to its delivery points from new supply sources and traditional low cost pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector has mitigated this risk by entering into long-term firm transportation contracts and the effectiveness of these contracts is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Vector also faces potential competition from new sources of natural gas, such as the Marcellus and Utica shale formation, which are in close proximity to the Chicago Hub. The further development of these shale formations could provide an alternate source of gas to the Chicago Hub as well as decrease the northeastern region of the United States' reliance on natural gas imports from Canada. However, the emergence of the Marcellus and Utica shale plays also provides potential opportunities to expand service on Vector.

Economic Regulation

The United States portion of Vector is subject to regulation by the FERC. If tariff rates are protested, the timing and amount of any recovery or refund of amounts recorded on the Consolidated Statements of Financial Position could be different from the amounts that are eventually recovered or refunded. In addition, future profitability of the entities could be negatively impacted.

The FERC has intensified its oversight of financial reporting, risk standards and affiliate rules and the Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued new pipeline standards and regulations on managing gas pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry groups to ensure it is informed of emerging issues in a timely manner.

CANADIAN MIDSTREAM

Canadian Midstream consists of the Company's 71% investment in Cabin located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin, as well as its 100% interest in Pipestone and varying interests (55% to 100%) in Sexsmith and its related sour gas gathering, compression and NGL handling facilities, located in the PRA region of northwest Alberta. The Company is the operator of Cabin.

The Canadian Midstream investments are underpinned by 20-year take-or-pay contracts with producers. Return on and of capital is based on the actual costs to purchase or construct the facilities. The Company is not impacted by throughput volumes; however, the Company shares in revenues obtained from available capacity sold to third parties or on volumes that exceed producer take-or-pay levels. Operating costs are passed through to producers.

Phase 1 of Cabin is currently 98% completed. Cabin producers are expected to request the Company to commission and start-up Phase 1 once natural gas price recovers to a more economic level to support the Horn River Basin's dry gas production. Phase 2 construction is approximately 40% complete and is in preservation mode awaiting producer's requests for completion. In December 2012, the Company started earning fees on its total investment made to date on both Phases 1 and 2. Construction of Pipestone and Sexsmith and related facilities were completed in 2014.

Results of Operations
Canadian Midstream earnings were $23 million for the year ended December 31, 2014 compared with earnings of $12 million for the year ended December 31, 2013. The increase in earnings reflected higher fees earned from the Company's investments in Cabin, Pipestone and Sexsmith. Pipestone earnings were higher due to incremental earnings from the final phase placed into-service in 2014 and higher volumes that exceeded take or pay levels.

Business Risks
The risks identified below are specific to Canadian Midstream. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization
Pipestone and Sexsmith are located within the liquids-rich PRA region which has seen significant development by area producers. In 2014, throughput volumes exceeded take-or-pay levels as available capacity was sold to third parties.

Cabin is located in the prolific Horn River Basin, one of the largest gas shale plays in North America. The current low gas price environment has slowed development due to the remote location and the lack of NGL content to supplement producer economics. Accelerated development of the Horn River is expected to be primarily tied to the development of LNG exports currently being pursued by Cabin producers.

ENBRIDGE OFFSHORE PIPELINES
Offshore is comprised of 11 active natural gas gathering and FERC-regulated transmission pipelines and one active oil pipeline with a capacity of 60,000 bpd, in four major corridors in the Gulf of Mexico, extending to deepwater developments. These pipelines include almost 2,100 kilometres (1,300 miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d. Offshore currently moves approximately 40% of total offshore gas production and 60% of deepwater gas production through its systems in the Gulf of Mexico.

Results of Operations
Offshore adjusted loss was $2 million for each of the years ended December 31, 2014 and 2013, respectively. Offshore losses reflected persistent weak gas volumes due to decreased production in the Gulf of Mexico. Offshore adjusted earnings also reflected the absence of earnings from the disposals of certain non-core assets that were finalized in March and November 2014, respectively. Partially offsetting the adjusted losses were incremental earnings from the completion of the Jack St. Malo portion of the WRGGS in December 2014 and cost savings achieved from the Company's decision not to renew windstorm insurance coverage effective May 2013. Offshore results are expected to improve with a full year of the Jack St. Malo portion of WRGGS and the expected 2015 third quarter completion and in-service of both the Big Foot gas portion of WRGGS and the Big Foot Pipeline.

For the year ended December 31, 2013, Offshore incurred an adjusted loss of $2 million compared with an adjusted loss of $3 million for the year ended December 31, 2012. Positive factors impacting the change in Offshore results included the Venice Condensate Stabilization Expansion (Venice) placed into service in November 2013, cost savings achieved from the Company's election not to renew windstorm insurance coverage and lower depreciation expense. However, more than offsetting these positive factors were persistent weak gas volumes on the majority of Offshore's pipelines due to decreased production in the Gulf of Mexico.

Transportation Contracts
The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ) over the expected production life. Some contracts have minimum throughput volumes that are subject to ship-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current delivery

expectations. The majority of long-term transport rates are market-based, with revenue generation directly tied to actual production deliveries. Some of the systems operate under a cost-of-service methodology, including certain lines under FERC regulation.

The business model to be utilized for the WRGGS, Big Foot Pipeline, Venice, Heidelberg Pipeline and Stampede Pipeline projects differs from the historic model. These new projects have a base level return that is locked in through either ship-or-pay commitments or fixed demand charge payments. If volumes reach a producer's anticipated levels, the return on these projects may increase. In addition, Enbridge has minimal capital cost risk on these projects and commercial agreements continue to contain life-of-lease commitments. The WRGGS and Big Foot Pipeline project agreements provide for recovery of actual capital costs to complete the project in fees payable by producers over the contract term. The Stampede Pipeline project provides for a capital cost risk sharing mechanism whereby Enbridge is exposed to a portion of the capital costs in excess of an agreed upon target. Conversely, Enbridge can recover in fees from producers a portion of the capital cost savings below the agreed upon target. Adjustments are allowed for many of Heidelberg Pipeline's project variables that impact its cost, with Enbridge bearing the residual capital cost risk after these adjustments have been applied.

Asset Impairment

In December 2012, the Company recorded 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 in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas in the Gulf of Mexico that have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

Business Risks

The risks identified below are specific to Offshore. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

A decrease in gas volumes transported by Offshore natural gas pipelines can directly affect revenues and earnings. Low natural gas prices, in part due to the prevalence of onshore shale gas, have resulted in reduced investment in exploration activities and producing infrastructure. Offshore diversifies its risk of declining gas production through the construction of crude oil pipelines. To date, crude oil prices have supported stable offshore investment; however, a decline in crude oil prices for a sustained period of time could change the potential for future investment opportunities. Further, a sustained decline in either natural gas or crude oil commodity prices could also impact the ability of the Company to recover its investment in long-lived offshore assets.

Competition

There is competition for new and existing business in the Gulf of Mexico, with multiple parties competing to construct and operate export pipelines for future deepwater discoveries. Offshore has been able to capture key opportunities, often allowing it to more fully utilize existing capacity. Offshore's gas pipelines serve a majority of the strategically located deepwater host platforms, positioning it favourably to make incremental investments for new platform connections and receive additional transportation volumes from new developments that may be tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the Big Foot Pipeline, Heidelberg Pipeline and Stampede Pipeline projects. Due to natural production decline, offshore pipelines often have available capacity, resulting in significant competition for new developments in the Gulf of Mexico. Competitive dynamics may impact the ability of the Company to recover its investment in long-lived offshore assets.

Natural Disaster Incidents
Adverse weather, such as hurricanes and tropical storms, may impact Offshore's financial performance directly or indirectly. Direct impacts may include damage to offshore facilities resulting in lower throughput, as well as inspection and repair costs. Indirect impacts may include damage to third party production platforms, onshore processing plants and pipelines that may decrease throughput on offshore systems.

The occurrence of hurricanes in the Gulf of Mexico increases the cost and availability of insurance coverage. On May 1, 2013, the Company elected not to renew windstorm coverage on its Offshore asset portfolio. The Company expects to reassess the market for windstorm coverage and revisit the possible purchase of coverage in future years as the Company's portfolio of Offshore assets is expected to increase. Enbridge facilities are engineered to withstand hurricane forces and constant monitoring of weather allows for timely evacuation of personnel and shutdown of facilities; however, damages to assets or injuries to personnel may still occur.

OTHER
Other includes 1,300 MW of net renewable power generating capacity out of the net enterprise-wide portfolio of 1,600 MW. The balance of the portfolio is held by the Fund. Also included in Other is the Montana-Alberta Tie-Line (MATL), the Company's first power transmission asset.

To optimize funding of its enterprise-wide slate of growth projects, Enbridge may, from time to time, drop down assets to its sponsored vehicles. In 2012, Greenwich Wind Energy Project (Greenwich), Amherstburg Solar Project (Amherstburg) and Tilbury Solar Project (Tilbury) were transferred to the Fund. Earnings contributions from these assets, net of noncontrolling interests, are reflected within Sponsored Investments from the date the assets were transferred to the Fund. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions.*

Results of Operations
Adjusted loss from Other was $4 million for the year ended December 31, 2014 compared with adjusted earnings of $4 million for the year ended December 31, 2013. The decrease in adjusted earnings reflected lower southbound revenues on MATL combined with its higher depreciation expense and financing costs and higher business development costs not eligible for capitalization within Other. Partially offsetting the decrease in adjusted earnings was the positive impact of new wind farms placed into service over the past two years.

Adjusted earnings from Other for the year ended December 31, 2013 were $4 million compared with $10 million for the year ended December 31, 2012. The decrease in adjusted earnings was attributable to the transfer of certain renewable energy assets to the Fund in December 2012, as well as lower contributions from the Cedar Point Wind Energy Project due to lower wind resources. Partially offsetting the decrease in adjusted earnings were earnings from Lac Alfred, which commenced commercial operations in phases in 2013.

Lac Alfred and Massif du Sud Wind Projects
In September 2014, the Company entered into an agreement to purchase additional interests in the 300-MW Lac Alfred and the 150-MW Massif du Sud from existing partner, EDF EN Canada Inc. Under the agreement, Enbridge invested 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 closed in December 2014 and Enbridge now holds an 80% interest in Massif du Sud.

SPONSORED INVESTMENTS

EARNINGS

	2014	2013	2012
(millions of Canadian dollars)			
Enbridge Energy Partners, L.P. (EEP)	**197**	165	141
Enbridge Energy, Limited Partnership (EELP)	**107**	38	38
Enbridge Income Fund (the Fund)	**125**	110	85
Adjusted earnings	**429**	313	264
EEP - changes in unrealized derivative fair value gains/(loss)	**5**	(6)	(2)
EEP - leak remediation costs	**(12)**	(44)	(9)
EEP - make-up rights adjustment	**(1)**	-	-
EEP - asset impairment loss	**(2)**	-	-
EEP - employee severance costs	**(1)**	-	-
EEP - leak insurance recoveries	**-**	6	24
EEP - tax rate differences/changes	**-**	(3)	-
EEP - gain on sale of non-core assets	**-**	2	-
EEP - NGL trucking and marketing investigation costs	**-**	-	(1)
EEP - prior period adjustment	**-**	-	7
The Fund - changes in unrealized derivative fair value gains	**3**	-	-
The Fund - drop down transaction costs	**(2)**	-	-
Earnings attributable to common shareholders	**419**	268	283

Adjusted earnings from Sponsored Investments were $429 million for the year ended December 31, 2014 compared with $313 million for the year ended December 31, 2013 and $264 million for the year ended December 31, 2012. The increase in adjusted earnings reflected new assets placed into service in EEP, primarily the Line 6B replacement and expansion, along with higher throughput on EEP's Lakehead and North Dakota System. Enbridge also benefitted from the completion of Line 6B replacement and expansion through its 75% interest in EELP. Within the Fund, higher earnings were primarily driven by an increased asset base and associated earnings impact from the completion of asset drop down from Enbridge.

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 each period included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Line 6B Crude Oil Release.*
- Earnings from EEP for 2014 included a make-up rights adjustment.
- Earnings from EEP for 2014 included an asset impairment loss.
- Earnings from EEP for 2014 included unusual employee severance costs triggered by redundancies in EEP's natural gas and NGL businesses.
- Earnings from EEP for 2013 and 2012 included insurance recoveries associated with the Line 6B crude oil release. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – 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 EEP for 2013 included a gain on sale of non-core assets.
- Earnings from EEP for 2012 reflected charges for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.
- Earnings from EEP for 2012 reflected a non-recurring out-of-period adjustment.
- Earnings from the Fund for 2014 included unrealized fair value gains on derivative financial instruments.

- Earnings from the Fund for 2014 included costs incurred in relation to a transaction to transfer natural gas and diluent pipeline interests to the Fund. See *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions.*

ENBRIDGE ENERGY PARTNERS, L.P.

EEP owns and operates crude oil and liquid petroleum transportation and storage assets; natural gas and NGL gathering, treating, processing, transportation assets; and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Canadian Mainline in the United States, the Mid-Continent Crude Oil System consisting of an interstate crude oil pipeline and storage facilities, a crude oil gathering system and interstate pipeline system in North Dakota and natural gas assets located primarily in Texas. Subsidiaries of Enbridge provide services to EEP in connection with the operation of its liquids assets, including the Lakehead System.

Economic Interest

Enbridge's ownership interest in EEP is impacted by EEP's issuance and sale of its Class A common units. To the extent Enbridge does not fully participate in these offerings, the Company's economic interest in EEP is reduced. At December 31, 2014, Enbridge's economic interest in EEP was 33.7% (2013 - 20.6%; 2012 - 21.8%). The Company's average economic interest in EEP during 2014 was 27.3% (2013 - 21.1%; 2012 - 23.0%). The increase in Enbridge's economic interest in EEP largely reflected the impact of the restructuring of EEP's equity in 2014 as discussed below. Additionally, Enbridge also holds a US$1.2 billion investment in EEP preferred units. For further discussion, refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – EEP Preferred Unit Private Placement and Joint Funding Option Exercise*.

Equity Restructuring

In June 2014, EEP and Enbridge announced an agreement to restructure EEP's equity with the objective of enhancing the economics of EEP's investment projects and growth opportunities, while at the same time re-establishing EEP as a strong sponsored vehicle and as an effective source of funding for Enbridge via future asset monetization.

Effective July 1, 2014, Enbridge Energy Company, Inc. (EECI), 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 2014 third and fourth quarter distributions 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 common 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 after 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.

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders. Under the Partnership Agreement, EECI as GP receives incremental incentive cash distributions, which represent incentive income on the portion of cash distributions (on a per unit basis) that exceed certain target thresholds. Prior to the Equity Restructuring, distributions to common unitholders and the GP were made on the basis of the following target thresholds:

	Unitholders including Enbridge	GP Interest
Quarterly cash distributions per unit:		
Up to US$0.2950 per unit	98%	2%
First target - US$0.2950 per unit up to $0.3500 per unit	85%	15%
Second target - US$0.3500 per unit up to $0.4950 per unit	75%	25%
Over second target - cash distributions greater than US$0.4950 per unit	50%	50%

Following the Equity Restructuring on July 1, 2014, distributions to common unitholders and the GP are made as follows:

	Unitholders including Enbridge	GP Interest
Quarterly cash distributions per unit:		
Up to US$0.5345 per unit	98%	2%
First target - cash distributions over US$0.5345 per unit	75%	25%

In July 2014, EEP increased its quarterly distribution from US$0.5435 per unit to common unitholders to US$0.5550. On December 23, 2014, EEP announced it would further increase its quarterly distribution to US$0.5700 per unit to common unitholders following the announcement that the Alberta Clipper Drop Down was finalized. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Alberta Clipper Drop Down*.

In 2014, Enbridge received from EEP, incentive distributions of US$39 million (2013 - US$130 million; 2012 - US$116 million). Also in 2014, Enbridge received distributions of US$108 million from Class D units which were issued under the Equity Restructuring discussed above.

Results of Operations

Adjusted earnings from EEP were $197 million for the year ended December 31, 2014 compared with $165 million for the year ended December 31, 2013. Within EEP's liquids business, adjusted earnings increased primarily as a result of new assets placed into service during 2013 and 2014, combined with higher throughput and tolls on its major liquids pipelines. New assets placed into service included 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 a larger workforce partially 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 mainly due to decreased drilling activity had a negative impact on adjusted earnings. Finally, EEP's contribution to Enbridge's adjusted earnings reflected higher earnings from Enbridge's May 2013 investment in preferred units of EEP, higher incentive distributions and distributions from Class D units which were issued under the Equity Restructuring.

Adjusted earnings from EEP were $165 million for the year ended December 31, 2013 compared with $141 million for the year ended December 31, 2012. The adjusted earnings increased primarily due to distributions received from Enbridge's May 2013 investment in preferred units of EEP and higher incentive distributions. Also contributing to higher adjusted earnings were contributions from EEP's liquids business due to higher tolls on EEP's major liquids pipeline assets and the positive impact of new assets placed into service. Partially offsetting the increase in adjusted earnings were lower volumes on the North Dakota system due to wide crude oil price differentials that made transportation by rail competitive, although tightening crude oil price differentials in the second half of 2013 resulted in some volumes returning to the North Dakota system. EEP's adjusted earnings also reflected costs related to the completion of hydrostatic testing on Line 14 of its Lakehead System, as well as higher depreciation expense associated with new assets placed into service. Also offsetting the adjusted earnings increase were lower NGL prices and volumes in EEP's natural gas and NGL businesses and higher operating and administrative expense, primarily from an increased workforce.

Alberta Clipper Drop Down

In September 2014, Enbridge and EEP announced Enbridge's proposal to transfer its 66.7% interest in the United States segment of the Alberta Clipper Pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP. At the time of the announcement, EEP already owned the remaining 33.3% interest in the United States segment of Alberta Clipper. On January 2, 2015, the drop down closed for aggregate consideration of US$1 billion, consisting of approximately US$694 million of Class E equity units issued to Enbridge by EEP and the repayment of approximately US$306 million of indebtedness owed to Enbridge. The terms of the transfer were reviewed and recommended by an independent committee of EEP.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at Enbridge's option. However, the Class E units are not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at EEP's option after 30 years, if not converted earlier by Enbridge. The units had a liquidation preference equal to their notional value at December 23, 2014 of US$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units.

The aggregate consideration of US$1 billion corresponds to an approximate 10.7 times multiple of expected 2015 Alberta Clipper Earnings before interest, tax, depreciation and amortization (EBITDA). If after two years, the cumulative adjusted EBITDA of the Alberta Clipper Pipeline for fiscal years 2015 and 2016 is more than five percent below the EBITDA projections for those years, a number of Class E units representing US$50 million of value will be cancelled by EEP effective as of April 1, 2017 for no consideration.

The United States segment of the Alberta Clipper Pipeline is a 523-kilometre (325-mile), 36-inch diameter crude oil pipeline from the United States border near Neche, North Dakota to Superior, Wisconsin. The initial capacity of the line is 450,000 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 and were not included as part of the above noted drop down transaction. Refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the EPA, the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the EPA 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.

As of December 31, 2014, regulatory authority transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at December 31, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($193 million after-tax attributable to Enbridge), which is an increase of US$86 million ($12 million after-tax attributable to Enbridge) as compared with December 31, 2013. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. The total cost increase of US$86 million during the year ended December 31, 2014, is primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake and 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 December 31, 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.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in

Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

As at December 31, 2014, the total estimated cost for the Line 6A crude oil release is now approximately US$51 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties, which is an increase of US$3 million (nil after-tax attributable to Enbridge) as compared to December 31, 2013 primarily due to additional legal expenses. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP's remediation spending through December 31, 2014, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at December 31, 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 of the 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 and has since amended its lawsuit such that it now includes only one insurer.

Of the remaining US$103 million coverage limit, US$85 million is the subject matter of the lawsuit against the one insurer while the recovery of the remaining US$18 million is awaiting resolution of that lawsuit. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in the 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 seven 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 December 31, 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 PHMSA, 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 further measures directed toward enhancing spill prevention, leak detection, emergency response to environmental events. The cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

One claim related to Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the PHMSA on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, EEP received a letter from the PHMSA approving its request to continue the normal operation of Line 14 without pressure restrictions.

The total estimated cost for the repair and remediation associated with the Line 14 crude oil release remains at approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenues and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

Midcoast Energy Partners, L.P. – Initial Public Offering and Drop Down of Additional Interests

EEP holds its natural gas and NGL midstream assets through a combination of direct holding and indirect holdings through MEP, a publicly listed partnership trading on the New York Stock Exchange. In May 2013, EEP formed MEP as its wholly-owned subsidiary. Subsequently, on November 13, 2013, MEP completed its initial public offering of 18.5 million Class A common units representing limited partner interests and subsequently issued an additional 2.8 million Class A common units pursuant to an underwriters' over-allotment option. MEP received proceeds of approximately US$355 million. Upon finalization of the offering, MEP's initial assets consisted of an approximate 39% ownership interest in EEP's natural gas and NGL midstream business. EEP retained a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP, in addition to its 61% direct interest in the natural gas and NGL midstream assets.

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 continued to retain a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP. However, EEP's direct interest in entities or partnerships holding the natural gas and NGL midstream operations reduced from 61% to 48%, with the remaining ownership held by MEP. The completion of these transactions 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.

Intercompany Accounts Receivable Sale
On June 28, 2013, certain of EEP's subsidiaries entered into a Receivables Purchase Agreement (the Receivables Agreement) with a wholly-owned subsidiary of Enbridge, whereby Enbridge will purchase on a monthly basis certain trade and accrued receivables of such subsidiaries through December 2016. Pursuant to the Receivables Agreement, as amended on September 20, 2013, and again on December 2, 2013, at any one point the accumulated purchases, net of collections, shall not exceed US$450 million. The primary objective of the accounts receivable transaction is to further enhance EEP's available liquidity and its cash available from operations for payment of distributions during the next few years until EEP's large growth capital commitments are permanently funded, as well as to provide an annual saving in EEP's cost of funding during this period.

EEP Preferred Unit Private Placement and Joint Funding Option Exercise
In May 2013, Enbridge invested US$1.2 billion in preferred units of EEP to reduce the amount of near-term external funding required by EEP to fund its share of the Company's organic growth program. Concurrent with the issuance, EEP also announced it expected to exercise its option in each of the Eastern Access and Lakehead System Mainline Expansion joint funding agreements to reduce its economic interest and associated funding in the respective projects. On June 28, 2013, EEP exercised each of the options and both projects are now being funded 75% by Enbridge and 25% by EEP. EEP will retain the option to increase its economic interest back up to 40% in each project within one year of the final project in-service dates.

Enbridge Energy Management, L.L.C. Share Issuance
Enbridge's ownership in EEP is held through a combination of direct interest, including a 2% GP interest, and indirect interest through Enbridge Energy Management, L.L.C. (EEM). In 2013, EEM completed two separate issuances of Listed Shares. In March 2013, EEM completed the issuance of 10.4 million Listed Shares for net proceeds of approximately US$273 million and in September 2013, EEM completed a further issuance of 8.4 million Listed Shares for net proceeds of approximately US$236 million. Enbridge did not purchase any of the offered shares. EEM subsequently used the net proceeds from each of the offerings to invest in an equal number of i-units of EEP.

In connection with these issuances, the Company made capital contributions of US$6 million and US$5 million in March and September 2013, respectively, to maintain its 2% GP interest in EEP. The proceeds from the issuances were used by EEP to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
EELP holds assets that are jointly funded by Enbridge and EEP. Included within EELP is the United States segment of Alberta Clipper Pipeline. The United States portion of the Alberta Clipper Pipeline connects with the Canadian portion of Alberta Clipper Pipeline at the border near Neche, North Dakota and provides transportation service to Superior, Wisconsin. Enbridge funded 66.7% of the project's equity requirements through EELP, while 66.7% of the debt funding was made through EEP. On January 2, 2015, an agreement to drop down Enbridge's 66.7% interest in the United States segment of Alberta Clipper to EEP was finalized. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Alberta Clipper Drop Down*.

Also within EELP is Enbridge's partnership interest in both the Eastern Access and Lakehead Mainline Expansion projects. In 2012, EELP amended and restated its limited partnership agreement to establish a series of additional partnership interests in both the Eastern Access and Lakehead Mainline Expansion projects. Both of these projects will be funded 75% by Enbridge and 25% by EEP. For further details on the respective projects, refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Eastern Access* and *Growth Projects – Commercially*

Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion.

Results of Operations

Earnings from EELP were $107 million for the year ended December 31, 2014 compared with $38 million for the year ended December 31, 2013. Higher earnings reflected contributions from assets recently placed into service, most notably the expansion of Line 6B from 240,000 bpd to 500,000 bpd completed in phases during 2014 as part of the Company's Eastern Access Program. Higher earnings from Eastern Access also reflected a higher surcharge rate due to the Lakehead System filing delay and other true-up adjustments. Also positively impacting earnings were higher tolls on Alberta Clipper.

Earnings from EELP were $38 million for both the years ended December 31, 2013 and 2012. EELP earnings were comparable between years due to offsetting factors. Alberta Clipper earnings decreased and reflected lower tolls, which took effect April 1, 2013. Variations in Alberta Clipper earnings from the regulated allowed return on rate base are recovered from or refunded to shippers in the following year. The decrease in Alberta Clipper earnings were offset by the positive impact of incremental revenues from several small components of the Eastern Access project which were placed into service in 2013, including the Line 5 expansion.

BUSINESS RISKS

The risks identified below are specific to EEP and EELP. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Asset utilization risk for EEP's liquids business shares similar risk characteristics to Liquids Pipelines as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of EEP's assets. The profitability of EEP's liquids business depends to some extent on the throughput of products transported on its pipeline systems, and a decrease in volumes transported can directly and adversely affect revenues and earnings.

Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions, outside of EEP's control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on EEP's pipelines. However, the long-term outlook for Canadian crude oil production, particularly from western Canada, and increasing United States domestic production are expected to maintain a steady supply of crude oil.

EEP seeks to mitigate utilization constraints within its control. The market access and expansion projects under development are expected to reduce capacity bottlenecks and introduce new markets for customers. In conjunction with Liquids Pipelines, EEP seeks to optimize capacity and throughput on its existing assets by working with the shipper community to enhance scheduling efficiency and communications, as well as making continuous improvements to scheduling models and timelines to maximize throughput.

EEP's natural gas gathering assets are also subject to market fundamentals affecting natural gas, NGL and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas and, with current low natural gas prices, infrastructure plans have been increasingly deferred or cancelled. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Supply for the marketing operations depends to a large extent on the natural gas reserves and rate of drilling within the areas served by the natural gas business. Demand is typically driven by weather-related factors, with respect to power plant and utility customers, and industrial demand. EEP's marketing business uses third party storage to balance supply and demand factors.

Operational and Economic Regulation
Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of EEP's assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on EEP's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on EEP.

EEP's economic regulation is driven primarily through its ownership of interstate oil pipelines and certain activities within its intrastate natural gas pipelines, which are regulated by the FERC or state regulators. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on EEP's revenues and earnings. Delays in regulatory approvals could result in cost escalations and constructions delays, which also negatively impact EEP's operations. Additionally, while EEP's gas gathering pipelines are not currently subject to FERC rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls on new and existing pipelines. However, despite the best efforts on the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Competition
EEP's Lakehead System, the United States portion of the liquids pipelines mainline, is a major crude oil export conduit from the WCSB. Other existing competing carriers and pipeline proposals to ship western Canadian liquids hydrocarbons to markets in the United States represent competition for the Lakehead System, including proposed projects expected to serve the Gulf Coast market. EEP's Mid-Continent and North Dakota systems also face competition from existing competing pipelines, proposed future pipelines and existing and alternative gathering facilities, predominately rail. Competition for EEP's storage facilities includes large integrated oil companies and other midstream energy partnerships.

Other interstate and intrastate natural gas pipelines (or their affiliates) and other midstream businesses that gather, treat, process and market natural gas or NGL represent competition to EEP's natural gas segment. The level of competition varies depending on the location of the gathering, treating and processing facilities. However, most natural gas producers and owners have alternate gathering, treating and processing facilities available to them, including those owned by competitors that are substantially larger than EEP.

EEP's marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and natural gas producers, independent aggregators and regional marketing companies.

Commodity Price Risk
EEP's gas processing business is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks have been managed by using physical and financial

contracts to fix the prices of natural gas and NGL. Certain of these financial contracts do not qualify for cash flow hedge accounting; therefore, EEP's earnings are exposed to associated changes in the mark-to-market value of these contracts.

ENBRIDGE INCOME FUND

The Fund has investments in three core businesses: renewable and alternative power generation (Green Power); crude oil and liquids pipeline transportation and storage (Liquids Transportation and Storage); and a 50% interest in Alliance Pipeline (Natural Gas Transmission). Within Green Power, the Fund has interests in over 500 MW of net renewable and alternative power generation capability. Liquids Transportation and Storage operates a crude oil gathering system and trunkline pipeline in southern Saskatchewan and southwestern Manitoba, connecting to Enbridge's mainline pipeline to the United States (the Saskatchewan System). The Fund's Liquids Transportation and Storage also includes the Canadian portion of the Bakken Expansion Program, interests in Southern Lights Pipeline, and the Hardisty Contract Terminals and Hardisty Storage Caverns located near Hardisty, Alberta.

Enbridge Income Fund Drop Down Transactions

In November 2014, the Fund completed the acquisition of Enbridge's 50% interest in Alliance Pipeline US and the subscription for and purchase of 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 transaction was approximately $1.8 billion. Enbridge received on closing approximately $421 million in cash and $461 million in the form of preferred units of Enbridge Commercial Trust (ECT), a subsidiary of the Fund. Under the agreement, Enbridge provided bridge debt financing (Bridge 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. In November 2014, the Fund issued $1,080 million of medium-term notes with a portion of these proceeds used to fully repay the Bridge Financing to Enbridge. The Fund also issued $421 million of trust units to ENF to fund the cash component of the consideration. Enbridge applied approximately $84 million of cash to acquire additional common shares of ENF, thereby maintaining its 19.9% interest in ENF. Enbridge's overall economic interest in the Fund was reduced from 67.3% to 66.4% upon completion of the transaction.

In December 2012, the Fund acquired the Hardisty Storage Caverns, Hardisty Contract Terminals and the Greenwich, Amherstburg and Tilbury projects from Enbridge and its wholly-owned subsidiaries for an aggregate purchase price of approximately $1.2 billion, financed in part by the issuance of additional ordinary trust units of the Fund to ENF and ECT preferred units to Enbridge. ENF in turn issued additional common shares to the public and to Enbridge. Enbridge also provided Bridge Financing to the Fund for the balance of the purchase price, which was repaid in December 2012. Enbridge's overall economic interest in the Fund was reduced from 69.2% to 67.7% upon completion of the transaction.

The asset transfers described above occurred between entities under common control of Enbridge, and the intercompany gains realized by the selling entities in each of the years ended December 31, 2014 and 2012 have been eliminated from the Consolidated Financial Statements of Enbridge. However, as these transactions involved the sale of shares and partnership units, all tax consequences have remained in consolidated earnings and resulted in charges of $157 million and $56 million in 2014 and 2012, respectively.

Through these transactions, which essentially resulted in a partial monetization of the assets by Enbridge through sale to noncontrolling interests (being ENF's public shareholders), Enbridge realized a source of funds of $323 million and $213 million for the years ended December 31, 2014 and 2012, respectively, as presented within Financing Activities on the Consolidated Statements of Cash Flows.

In December 2014, Enbridge also announced a proposed transfer of Canadian Liquids Pipelines and certain renewable energy assets to the Fund. For further details, refer to *Canadian Restructuring Plan.*

Results of Operations

Adjusted earnings for the Fund for the year ended December 31, 2014 were $125 million compared with $110 million for the year ended December 31, 2013. The increase in adjusted earnings reflects the incremental earnings from Enbridge's transfer of natural gas and diluent pipeline interests to the Fund in November 2014 as well as strong performance from the Fund's liquids business. Partially offsetting the increase in adjusted earnings were lower wind resources across several of the Fund's wind farms and higher interest expense associated with an increase in external debt issued in 2014 to support the acquisition of the natural gas and diluent pipeline interests. Finally, adjusted earnings were also positively impacted by higher preferred unit distributions received from the Fund.

Earnings for the Fund for the year ended December 31, 2013 were $110 million compared with $85 million for the year ended December 31, 2012. The increase in earnings was attributable to earnings from crude oil storage and renewable energy assets acquired from Enbridge and its wholly-owned subsidiaries in December 2012. Earnings were also positively impacted by higher preferred unit distributions received from the Fund and earnings from the Bakken Expansion Program, which commenced operations in March 2013. Partially offsetting these sources of earnings growth was higher interest expense and a one-time charge recognized in the first quarter of 2013 related to the write-off of a regulatory deferral balance for which recoverability is no longer probable.

Westspur Settlement

On April 1, 2013, the Fund announced it concluded a settlement (the Settlement) with a group of shippers resulting in new tolls on the Westspur System. At the request of certain shippers that did not execute the settlement, the NEB did not remove the interim status from the historical tolls and made the new tolls interim as well. A modified agreement was subsequently entered into with substantially all of the shippers, and such shippers requested the NEB make both the historical tolls and the new tolls (collectively, the Tolls) final. On February 6, 2014, the NEB ordered the Tolls final.

The Settlement establishes a toll methodology for an initial term of five years, with additional one year renewal terms unless otherwise terminated. Pursuant to the Settlement, the Tolls on the Westspur System will be fixed and increased annually with reference to an inflation index, subject to throughput remaining within a prescribed volume band close to volumes recently transported on the Westspur System. The Settlement resulted in the discontinuance of rate-regulated accounting for the Westspur System and the Fund recorded an after-tax write-down of approximately $12 million ($4 million after-tax attributable to Enbridge) in the first quarter of 2013 related to a deferred regulatory asset that will not be collected under the terms of the Settlement.

Alliance Pipeline Recontracting

On July 15, 2013, Alliance Pipeline announced that beginning on August 15, 2013, customers could express interest in shipping on the Alliance Pipeline for periods following the December 2015 expiry of the majority of the existing contracts. Alliance Pipeline outlined the services to be offered as well as the precedent agreement process to be followed. On May 22, 2014, Alliance Canada filed an application with the NEB for regulatory approval of its new services offering and the related tolls and tariff provisions required to implement the new services. Alliance US intends to file an application with the FERC in mid-2015 regarding its new services offering. Given its unique ability to cost-effectively transport liquids-rich natural gas, and the supply growth in basins it runs through, it is expected that the Alliance Pipeline will be well-utilized for the foreseeable future as evidenced by good progress made in securing precedent agreements with shippers. As of February 2015, over 90% of total targeted capacity, a combination of receipt and full path, has been secured with an average contract length of almost five years.

Incentive and Management Fees

Enbridge receives an annual base management fee for administrative and management services it provides to the Fund, plus incentive fees. Incentive fees are paid to Enbridge based on cash distributions paid by the Fund that exceed a base distribution amount. In 2014, the Company received incentive fees of $23 million (2013 - $20 million; 2012 - $12 million) before income taxes. Enbridge also provides management services to ENF. No additional fee is charged to ENF for these services provided the Fund is paying a fee to Enbridge.

BUSINESS RISKS

The risks identified below are specific to the Fund's three core businesses: Green Power; Liquids Transportation and Storage; and Alliance Pipeline. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Green Power

Asset Utilization

Earnings from Green Power assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Green Power projects are predicted using long-term historical data, wind and solar resources will be subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the Green Power facilities could lead to decreased earnings for the Fund. Additionally, inefficiencies or interruptions of Green Power facilities due to operational disturbances could also impact earnings. The Company may mitigate the risk of operational availability by establishing Operations and Maintenance contracts with the original equipment manufacturers that include a negotiated operational performance asset guarantee. The Company also monitors the operational performance and reliability of the assets on a 24-hour basis.

Liquids Transportation and Storage

Asset Utilization

Asset utilization risk for the Fund's liquids business shares similar risk characteristics to Liquids Pipelines as changing market fundamentals, capacity bottlenecks, including insufficient capacity downstream on the Canadian Mainline, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of the Fund's assets. The Fund is also exposed to throughput risk under certain tolling agreements applicable to the Saskatchewan System assets.

Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions, outside of the Fund's control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on the Saskatchewan System.

The Fund seeks to mitigate utilization risks within its control, including working with the shipper community on its tolling agreements. Additionally, volume risk is somewhat mitigated for the Westspur System due to the fact that toll surcharges or discounts will be applied should throughput increase or decrease on a sustained basis outside a pre-defined band set as defined in the agreement.

Competition

Liquids Transportation and Storage, including the Saskatchewan System, faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably rail. These alternative transportation options could charge rates or provide service to locations that result in greater netbacks for shippers, thereby reducing shipments on the Saskatchewan System or resulting in pressure to reduce tolls. The Saskatchewan System's right-of-way and expansion efforts provide a competitive advantage.

Operational and Economic Regulation

Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of the Fund's assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on the Fund's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Fund.

In relation to economic regulations, certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of the Fund and could adversely impact the timing and amount of recovery or settlement of regulatory balances.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls on new and existing pipelines. However, despite the best efforts of the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Alliance Pipeline

Asset Utilization

Currently, natural gas pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline to date has been relatively unaffected by the excess supply environment, as substantially all of its long-term capacity contracts extend until late 2015. However, excess capacity and depressed natural gas and crude prices have led to the prospect of a reduction or deferral of investment in upstream gas development, and could negatively impact the ability of Alliance Pipeline to recontract when its newly secured contracts expire beyond 2015. Additionally, increased supply from new shale developments including the Marcellus and Utica shale plays could displace gas from the WCSB to the United States midwest, further increasing re-contracting risk.

Re-contracting risk is partially mitigated as Alliance Pipeline is well-positioned to deliver incremental liquids-rich gas production from developments in the Montney, Duvernay and Bakken regions to the Aux Sable NGL fractionation plant. Alliance Pipeline is also engaged with market participants in developing new receipt facilities and services to expand its reach in transporting liquids-rich gas to premium markets. As noted above, Alliance Pipeline recontracting efforts are well advanced.

Competition

Alliance Pipeline faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects to transport gas from existing and new gas developments throughout North America. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance Pipeline because of location, facilities or other factors. In addition, any new or upgraded pipelines could charge tolls or rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of reducing future supply for Alliance Pipeline. The ability of Alliance Pipeline to cost-effectively transport liquids-rich gas serves to enhance its competitive position as evidenced by the successful recontracting to date.

Economic Regulation

Alliance Pipeline is subject to regulation by the NEB in Canada and the FERC in the United States. If tolls, rates, or tariffs are protested, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position could be different from the amounts that are eventually recovered or refunded. In addition, future profitability of the entities could be negatively impacted. On a yearly basis, following consultation with shippers, Alliance Pipeline files its annual rates with the NEB and FERC for approval.

CORPORATE

EARNINGS

	2014	2013	2012
(millions of Canadian dollars)			
Noverco Inc. (Noverco)	**43**	54	27
Other Corporate	**(69)**	(82)	(57)
Adjusted loss	**(26)**	(28)	(30)
Noverco - changes in unrealized derivative fair value gains/(loss)	**(5)**	4	(10)
Noverco - equity earnings adjustment	**-**	-	(12)
Other Corporate - changes in unrealized derivative fair value loss	**(378)**	(306)	(22)
Other Corporate - tax on intercompany gains on sale of assets	**(157)**	-	(56)
Other Corporate - gain on sale of investment	**14**	-	-
Other Corporate - drop down transaction costs	**(6)**	-	-
Other Corporate - foreign tax recovery	**-**	4	29
Other Corporate - impact of tax rate changes	**-**	18	(11)
Other Corporate - asset impairment loss	**-**	(6)	-
Other Corporate - unrealized foreign exchange loss on translation of intercompany balances, net	**-**	-	(17)
Loss attributable to common shareholders	**(558)**	(314)	(129)

Total adjusted loss from Corporate was $26 million for the year ended December 31, 2014 compared with adjusted losses of $28 million for the year ended December 31, 2013 and $30 million for the year ended December 31, 2012. 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 also recognized in the first quarter of 2013, Noverco adjusted earnings were slightly higher in 2014 compared with 2013 and mainly reflected stronger operating earnings from Gaz Metro Limited Partnership (Gaz Metro). Higher volumes within Gaz Metro's Quebec-based gas distribution franchise area, contributions from a full year of operations of power distribution assets acquired by Noverco in mid-2012, along with the gain on sale and equity earnings true-up adjustment noted above, drove higher Noverco adjusted earnings in 2013 compared with 2012. Adjusted loss in Corporate continued to reflect higher preference share dividends from an increase in the number of preference shares outstanding over the past two years; however, this was largely offset in 2014 by lower net Corporate segment finance costs.

Corporate loss was impacted by the following adjusting items:

- Noverco earnings for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- Noverco earnings for 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Other Corporate loss for each period included changes in the unrealized fair value losses on derivative financial instruments primarily related to forward foreign exchange risk management positions.
- Other Corporate loss for 2014 and 2012 were impacted by tax on intercompany gains on sales. See *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions*.
- Other Corporate loss for 2014 included a gain on sale of an investment.
- Other Corporate loss for 2014 included transaction costs associated with the proposed Canadian Liquids Pipelines financial restructuring plan, refer to *Canadian Restructuring Plan* and costs incurred in relation to a transaction to transfer natural gas and diluent pipeline interests to the Fund. See *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions.*
- Other Corporate loss for 2013 and 2012 were reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate loss for 2013 and 2012 were impacted by tax rate changes.
- Other Corporate loss for 2013 included charges related to asset impairment losses.
- Other Corporate loss for 2012 included net unrealized foreign exchange loss on the translation of foreign-denominated intercompany balances.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. Noverco is a holding company that owns approximately 71% of Gaz Metro, a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the state of Vermont. Noverco also holds, directly and indirectly, an investment in Enbridge common shares. In 2014, 2013 and 2012, the board of directors of Noverco authorized the sale of a portion of its Enbridge common share holding to rebalance Noverco's asset mix.

In 2014, Noverco sold 1.3 million Enbridge common shares through a secondary offering. Unlike the 2013 and 2012 transactions discussed below, Enbridge did not receive a dividend from Noverco for its share of the net after-tax proceeds. On May 28, 2013, Noverco sold 15 million Enbridge common shares through a secondary offering. Enbridge's share of the net after-tax proceeds of approximately $248 million was received as dividends from Noverco on June 4, 2013 and was used to pay a portion of the Company's quarterly dividend on September 1, 2013. A portion of this dividend did not qualify for the enhanced dividend tax credit in Canada and, accordingly, was not designated as an "eligible dividend". The dividend was a "qualified dividend" for United States tax purposes.

On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge's share of the proceeds of approximately $317 million was received as a dividend from Noverco on May 18, 2012 and was used to pay a portion of the Company's quarterly dividend on June 1, 2012. This portion of the quarterly dividend did not qualify for the enhanced dividend tax credit in Canada and, accordingly, was not designated as an "eligible dividend". The dividend was a "qualified dividend" for United States tax purposes.

A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investments which are based on the yield of 10-year Government of Canada bonds plus a margin of 4.3% to 4.4%.

Results of Operations

Noverco adjusted earnings decreased to $43 million for the year ended December 31, 2014 from $54 million for the year ended December 31, 2013. 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 also recognized in the first quarter of 2013, Noverco adjusted earnings were slightly higher for the year ended December 31, 2014 and reflected stronger operating earnings from Gaz Metro and higher preferred share dividend income.

Noverco adjusted earnings were $54 million for the year ended December 31, 2013 compared with $27 million for the year ended December 31, 2012. The increase in adjusted earnings was primarily attributable to higher volumes within Gaz Metro's Quebec-based gas distribution franchise area, contributions from a full year of operations of power distribution assets acquired in mid-2012 and the impact of a small one-time gain on sale of an investment in the first quarter of 2013 together with an equity earnings true-up adjustment recognized in the first quarter of 2013. Partially offsetting the adjusted earnings increase was a lower ROE allowed by the regulator for Gaz Metro. Noverco's investment in power distribution operations is subject to seasonality, similar to gas distribution operations, with the majority of its annual earnings achieved during the colder months of the first quarter. This seasonal pattern heightens the effect of the earnings increase attributable to the power distribution acquisition since the 2013 results included the first quarter, whereas 2012 did not given that the acquisition took place mid-year.

OTHER CORPORATE

Corporate also consists of the new business development activities, general corporate investments and financing costs not allocated to the business segments. Other corporate costs include dividends on preference shares as such dividends are a deduction in determining earnings attributable to common shareholders.

Results of Operations
Other Corporate adjusted loss was $69 million for the year ended December 31, 2014 compared with an adjusted loss of $82 million for the year ended December 31, 2013. The decrease in adjusted loss reflected lower net Corporate segment finance costs and lower income taxes partially offset by higher preference share dividends from an increase in the number of preference shares outstanding and higher operating and administrative costs.

Other Corporate adjusted loss was $82 million for the year ended December 31, 2013 compared with an adjusted loss of $57 million for the year ended December 31, 2012. The increased loss was attributable to dividends paid on additional preference shares issued, partially offset by lower net Corporate segment finance costs and lower operating and administrative costs.

Preference Share Issuances
Since July 2011, the Company has issued 260 million preference shares for gross proceeds of approximately $6,527 million with the following characteristics. See *Outstanding Share Data*.

	Gross Proceeds	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)						
Series B[5]	$500 million	4.0%	$1.00	$25	June 1, 2017	Series C
Series D[5]	$450 million	4.0%	$1.00	$25	March 1, 2018	Series E
Series F[5]	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H[5]	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J[5]	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L[5]	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N[5]	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O
Series P[5]	$400 million	4.0%	$1.00	$25	March 1, 2019	Series Q
Series R[5]	$400 million	4.0%	$1.00	$25	June 1, 2019	Series S
Series 1[5]	US$400 million	4.0%	US$1.00	US$25	June 1, 2018	Series 2
Series 3[5]	$600 million	4.0%	$1.00	$25	September 1, 2019	Series 4
Series 5[5]	US$200 million	4.4%	US$1.10	US$25	March 1, 2019	Series 6
Series 7[5]	$250 million	4.4%	$1.10	$25	March 1, 2019	Series 8
Series 9[5]	$275 million	4.4%	$1.10	$25	December 1, 2019	Series 10
Series 11[5]	$500 million	4.4%	$1.10	$25	March 1, 2020	Series 12
Series 13[5]	$350 million	4.4%	$1.10	$25	June 1, 2020	Series 14
Series 15[5]	$275 million	4.4%	$1.10	$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 *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 *For dividends declared, see* Liquidity and Capital Resources – Financing Activities.

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 were used to fund the Company's growth projects, reduce short term indebtedness and for other general corporate purposes.

On April 16, 2013, the Company completed the issuance of 13 million Common Shares for gross proceeds of approximately $600 million.

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 currently secured or under development. Access to timely funding from capital markets could be limited by factors outside Enbridge's control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, the Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. Furthermore, the Company targets to maintain sufficient standby liquidity to bridge fund through protracted capital markets disruptions. However, until the Canadian Restructuring Plan is complete, which is targeted for mid-2015, the Company may not access the public markets as regularly as in recent previous years. The Company has 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's financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles through which it can monetize assets, with the objective of diversifying funding sources and maintaining access to low cost capital.

In 2014, Enbridge continued to actively employ its sponsored vehicles to enhance its enterprise-wide funding program. Following a series of actions in 2013 by Enbridge to enhance liquidity at EEP for the next several years until its growth capital commitments are permanently funded, Enbridge took a further step in June 2014 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 lowering EEP's cost of capital and improving its growth outlook, thus increasing the incentive distributions to Enbridge and enhancing its ability to undertake drop down transactions and third party acquisitions. For further detail to the Equity Restructuring, refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Equity Restructuring*.

Following the Equity Restructuring, Enbridge and EEP announced in September 2014 a proposed drop down of Enbridge's 66.7% interest in the United States segment of the Alberta Clipper Pipeline to EEP, which subsequently closed in January 2015. Aggregate consideration for the transaction was US$1 billion, consisting of approximately US$694 million of Class E equity units issued to Enbridge by EEP and the repayment of approximately US$306 million of indebtedness owed to Enbridge. Refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Alberta Clipper Drop Down.*

In November 2014, Enbridge finalized an agreement to transfer natural gas and diluent pipeline interest to the Fund, a transaction that provided Enbridge approximately $1.2 billion of net funding for its growth capital program. Refer to *Sponsored Investments – Enbridge Income Fund – Enbridge Income Fund Drop Down Transactions.*

Finally, in December 2014, Enbridge announced the Canadian Restructuring Plan which accelerates the sponsored vehicle financing strategy. The Canadian Restructuring Plan contemplates the drop down of approximately $17 billion of Enbridge's Canadian Liquids Pipelines business and certain renewable energy assets to the Fund and is targeted to close mid-2015. For further details, refer to *Canadian Restructuring Plan.*

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

- Corporate - $460 million of common shares; $1,400 million of preference shares; $1,530 million of medium-term notes; US$1,500 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;
- Sponsored Investments - The Fund - $1,080 million of medium-term notes; 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. In addition to ensuring adequate liquidity, the Company actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company's committed credit facilities at December 31, 2014 and 2013.

		December 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**163**	**137**	300
Gas Distribution	2016-2019	**1,008**	**943**	**65**	707
Sponsored Investments	2016-2019	**4,531**	**2,745**	**1,786**	4,781
Corporate	2016-2019	**12,772**	**6,223**	**6,549**	11,775
Total committed credit facilities[2]		**18,611**	**10,074**	**8,537**	17,563

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 related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis. Excluded from December 31, 2014 total facilities above was Southern Lights project financing facilities of $28 million (2013 - $1,570 million). Included in the 2013 facilities for Southern Lights were $63 million for debt service reserve letters of credit.

In addition to the committed credit facilities noted above, the Company also has $361 million (2013 - $35 million) of uncommitted demand credit facilities, of which $80 million (2013 - $17 million) was unutilized as at December 31, 2014.

The Company's net available liquidity of $9,291 million at December 31, 2014 was inclusive of $1,261 million of unrestricted cash and cash equivalents and net of bank indebtedness of $507 million as reported on the Consolidated Statements of Financial Position.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2014, the Company was in compliance with all debt covenants and expects to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled Enbridge to obtain and maintain a strong credit profile. The Company actively monitors and manages key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at December 31, 2014, the Company's debt capitalization ratio was 63.1% compared with 58.2% as at December 31, 2013.

The Company invests a portion of its surplus cash in short-term investment grade instruments with creditworthy counterparties. Short-term investments were $308 million as at December 31, 2014 compared with $85 million as at December 31, 2013. Surplus cash at December 31, 2014 provides financing flexibility and will be used to fund the Company's growth projects.

There are no material restrictions on the Company's cash with the exception of cash in trust of $47 million related to cash collateral and 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.

Excluding current maturities of long-term debt, at December 31, 2014 and 2013 the Company had a negative working capital position of $296 million and $967 million, respectively, which contemplates the realization of assets and the liquidation of liabilities. In both periods, the major contributing factor is the funding the Company's growth capital program.

Despite this negative working capital, the Company has significant net available liquidity through committed credit facilities and other sources as previously discussed, which allow the funding of liabilities as they become due. As at December 31, 2014, the net available liquidity totalled $9,291 million. In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

December 31,	**2014**	2013
(millions of Canadian dollars)		
Cash and cash equivalents[1]	**1,308**	790
Accounts receivable and other[2]	**5,745**	5,021
Inventory	**1,148**	1,115
Assets held for sale[3]	**-**	17
Bank indebtedness	**(507)**	(338)
Short-term borrowings	**(1,041)**	(374)
Accounts payable and other[4]	**(6,524)**	(6,710)
Interest payable	**(264)**	(228)
Environmental liabilities	**(161)**	(260)
Working capital	**(296)**	(967)

1 Includes Restricted cash.
2 Includes Accounts receivable from affiliates.
3 Net of current liabilities held for sale.
4 Includes Accounts payable to affiliates.

OPERATING ACTIVITIES

Cash generated from operating activities was $2,547 million for the year ended December 31, 2014 (2013 - $3,341 million; 2012 - $2,874 million). Excluding the timing effect of changes in operating assets and liabilities, the Company has delivered a growing cash flow stream over the last two years.

The Company's cash flows from operating activities have been positively impacted in part by new Liquids Pipelines and Sponsored Investments assets placed into service over the past three years, as well as strong operating performance from the Company's core businesses, which included higher throughput from growing crude oil supply from western Canada and higher downstream refinery demand as discussed in *Performance Overview.* Partially offsetting these positive factors for 2014 were higher financing costs as the Company significantly advanced its funding and liquidity strategy in support of its long-term growth plan, as well as lower common dividends paid by Noverco compared with 2013. During the year ended December 31, 2014, no common dividends were paid by Noverco, whereas in 2013 a one-time common dividend of $248 million (2012 - $317 million) was paid upon realization of a gain on the disposition of a portion of its investment in Enbridge shares.

Enbridge's operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and sales volumes within Energy Services and Gas Distribution, the timing of tax payments, payment of power deposits to support the Company's growth projects, general variations in activity levels within the Company's businesses as well as timing of cash receipts and payments.

In 2014, the year-over-year change in cash from operating activities was impacted by an unfavourable variance of $1,312 million from changes in operating assets and liabilities, mainly attributable to fluctuations in crude oil prices in the marketing and liquids businesses during the fourth quarter resulting in lower accounts payable balances, as well as increases in natural gas prices and colder than normal weather in the gas distribution business during the first quarter which resulted in the Company accumulating a significant regulatory receivable.

In 2013, the year-over-year change in cash from operating activities was impacted by a favourable variance of $251 million for changes in operating assets and liabilities, mainly attributable to higher activity in the Company's marketing and gas distribution businesses, which had higher accounts payable balances resulting from higher purchases, partially offset by increases in accounts receivable and inventory balances.

INVESTING ACTIVITIES

Cash used in investing activities was $11,891 million for the year ended December 31, 2014 (2013 - $9,431 million, 2012 - $6,204 million) which represents an increase on a year-over-year basis primarily due to additions to property, plant and equipment associated with the construction of the Company's expansion initiatives as described in *Growth Projects – Commercially Secured Projects*. A summary of additions to property, plant and equipment for the years ended December 31, 2014, 2013 and 2012 is as follows:

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Liquids Pipelines	**5,914**	4,359	1,926
Gas Distribution	**603**	533	445
Gas Pipelines, Processing and Energy Services	**678**	744	933
Sponsored Investments	**3,269**	2,565	1,886
Corporate	**60**	34	4
Total capital expenditures	**10,524**	8,235	5,194

Other notable investing activities during 2014, 2013 and 2012 included the funding of various investments in joint ventures, primarily the Seaway Pipeline Twinning/Extension projects and the Texas Express NGL System. Additionally, investing activities included the acquisition of interests in various projects, most notably Magic Valley and Wildcat wind farms in 2014, and Silver State North Solar Project and Pipestone and Sexsmith in 2012.

FINANCING ACTIVITIES

Cash generated from financing activities was $9,770 million for the year ended December 31, 2014 (2013 - $5,070 million, 2012 - $4,395 million). The cash inflow from financing activities has increased over the 2012 to 2014 time frame as the Company executed its funding and liquidity strategy in support of its long-term growth plan.

During the year ended December 31, 2014, the Company increased its overall debt by $9,000 million (2013 - $3,392 million, 2012 - $1,795 million). The most significant contributor of the increase was the issuance of medium-term and senior notes, net of repayments, of $5,573 million during 2014 (2013 - $2,185 million, 2012 - $1,850 million) and the securement of additional credit facilities together with increased draws on such facilities and commercial paper, net of repayments, of $2,693 million during 2014 (2013 - $1,557 million, 2012 – $307 million of net repayments).

Furthermore, the Company issued preference shares during 2014 for net proceeds of $1,365 million (2013 - $1,428 million, 2012 - $2,634 million), as well as common shares for net proceeds of $478 million (2013 - $628 million, 2012 - $465 million). The additional preference and common shares outstanding during the year together with an 11% increase in the common share dividend rate, gave rise to an increase in dividends paid in 2014 compared with 2013 and 2012.

Financing activities also included transactions between the Company's Sponsored Investments and their public unitholders, also referred to as noncontrolling interests. During 2014, EEP, MEP and the Fund made distributions, net of contributions, of $79 million. During 2013 and 2012, sponsored vehicles received contributions, net of distributions, of $474 million and $191 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 year ended December 31, 2014, dividends declared were $1,177 million (2013 - $1,035 million), of which $749 million (2013 - $674 million) were paid in cash and reflected in financing activities. The remaining $428 million (2013 - $361 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 years ended December 31, 2014 and 2013, 36.4% and 34.9%, respectively, of total dividends declared were reinvested.

On December 3, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2015 to shareholders of record on February 16, 2015.

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

CONTRACTUAL OBLIGATIONS

Payments due under contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	35,457	2,043	4,263	2,817	26,334
Capital and operating leases	1,250	120	222	128	780
Long-term contracts	15,065	5,965	3,026	1,952	4,122
Pension obligations[2]	109	109	-	-	-
Total contractual obligations	51,881	8,237	7,511	4,897	31,236

1 Excludes interest. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements.

2 Assumes only required payments will be made into the pension plans in 2015. Contributions are made in accordance with independent actuarial valuations as at December 31, 2014. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $4,401 million which are expected to be paid over the next five years.

CONTINGENCIES

United States Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately seven 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 December 31, 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 PHMSA, 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 further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

One claim related to Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order.

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.

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)	852,086,414
Stock Options - issued and outstanding (18,239,010 vested)	35,241,492

1 Outstanding share data information is provided as at February 9, 2015.

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

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

QUARTERLY FINANCIAL INFORMATION

2014	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**10,521**	**10,026**	**8,297**	**8,797**	**37,641**
Earnings attributable to common shareholders	**390**	**756**	**(80)**	**88**	**1,154**
Earnings per common share	**0.48**	**0.92**	**(0.10)**	**0.11**	**1.39**
Diluted earnings per common share	**0.47**	**0.91**	**(0.10)**	**0.10**	**1.37**
Dividends paid per common share	**0.3500**	**0.3500**	**0.3500**	**0.3500**	**1.40**
EGD - warmer/(colder) than normal weather	**(33)**	**(4)**	**2**	**(1)**	**(36)**
Changes in unrealized derivative fair value (gains)/loss	**190**	**(430)**	**396**	**164**	**320**

2013	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	7,897	7,730	8,998	8,293	32,918
Earnings attributable to common shareholders	250	42	421	(267)	446
Earnings per common share	0.32	0.05	0.52	(0.33)	0.55
Diluted earnings per common share	0.31	0.05	0.51	(0.33)	0.55
Dividends paid per common share	0.3150	0.3150	0.3150	0.3150	1.26
EGD - warmer/(colder) than normal weather	6	(2)	-	(13)	(9)
Changes in unrealized derivative fair value (gains)/loss	207	246	(223)	613	843

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

A significant part of the Company's revenues are generated from its energy services operations. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices. Commodity prices do not directly impact earnings since these earnings reflect a margin or percentage of revenues that depends more on differences in commodity prices between locations and points in time than on the absolute level of prices.

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

The Company actively manages its exposure to market risks including, but not limited to, commodity prices 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 impacted the consolidated quarterly earnings included:

- Included in the fourth quarter of 2014 was the tax impact of an asset transfer between entities under common control of Enbridge. The intercompany gain realized by the selling entity has been eliminated from the Consolidated Financial Statements of Enbridge. However, as the transaction involved sale of partnership units, the tax consequences has remained in consolidated earnings and resulted in a charge of $157 million.

- Included in first and fourth quarter earnings for 2014 were $43 million and $14 million after-tax gain on the disposal of non-core Offshore assets. Earnings in the first quarter of 2014 also included a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.
- Included in earnings is the Company's share of after-tax leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $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. In the fourth quarter of 2014, the Company recognized an out-of-period adjustment of $5 million to reduce Enbridge's share of leak remediation costs recognized in the third quarter of 2014. Earnings also included insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013.
- 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 and fourth quarter of 2014, respectively.

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

RELATED PARTY TRANSACTIONS

Other than the drop down transactions between Enbridge and its sponsored vehicles previously mentioned, all related party transactions are undertaken in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million for the year ended December 31, 2014 (2013 - $6 million; 2012 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution, Gas Pipelines, Processing and Energy Services and Sponsored Investment have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to the Company for transportation services for the year ended December 31, 2014 were $256 million (2013 - $222 million; 2012 - $127 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services made natural gas and NGL purchases of $315 million (2013 - $99 million; 2012 - $15 million) from several joint venture affiliates during the year ended December 31, 2014.

Natural gas sales of $58 million (2013 - $10 million; 2012 - $7 million) were made by certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services to several joint venture affiliates during the year ended December 31, 2014.

Amounts receivable from affiliates include a series of loans to Vector totalling $183 million (2013 - $181 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates from 4% to 8%.

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 expense 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 expense, 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 via 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 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 4.1%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt 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 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, before the effect of income taxes.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**8**	56	(12)
Interest rate contracts	**(1,086)**	814	(46)
Commodity contracts	**50**	(9)	52
Other contracts	**13**	(2)	(3)
Net investment hedges			
Foreign exchange contracts	**(113)**	(81)	1
	(1,128)	778	(8)
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*			
Foreign exchange contracts[1]	**8**	(8)	1
Interest rate contracts[2]	**101**	107	(1)
Commodity contracts[3]	**4**	1	(3)
Other contracts[4]	**(7)**	-	2
	106	100	(1)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**216**	51	23
Commodity contracts[3]	**(6)**	(3)	(3)
	210	48	20
Amount of gains/(loss) from non-qualifying derivatives included in earnings			
Foreign exchange contracts[1]	**(936)**	(738)	120
Interest rate contracts[2]	**4**	(10)	(2)
Commodity contracts[3]	**1,031**	(496)	(765)
Other contracts[4]	**7**	(3)	(2)
	106	(1,247)	(649)

1 *Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity 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. However, until the Canadian Restructuring Plan is complete, which is targeted for mid-2015, the Company may not access the public markets as regularly as recent previous years. The Company has 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 December 31, 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. In order to mitigate this risk, the Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, 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.

GENERAL BUSINESS RISKS

Strategic and Commercial Risks

Public Opinion

Public opinion or reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which Enbridge operates as well as their opposition to development projects, such as Northern Gateway. Potential impacts of a negative public opinion may include loss of business, delays in project execution, legal action, increased regulatory oversight or delays in regulatory approval and higher costs.

Reputation risk often arises as a consequence of some other risk event, such as in connection with operational, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having strong corporate governance practices, including a Statement on Business Conduct, which requires all employees to certify their compliance with Company policy on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's CSR Policy, Climate Change Policy, Aboriginal and Native American Policy and the Neutral Footprint Initiative).

The Company's actions noted above are the key mitigation action against negative public opinion; however, the public opinion risk can not be mitigated solely by the Company's individual actions. The Company actively works with other stakeholders in the industry to collaborate and work closely with government and Aboriginal communities to enhance the public opinion of the Company, as well as the industry in which it operates.

Project Execution

As the Company increases its slate of growth projects, it continues to focus on completing projects safely, on-time and on-budget. However, the Company faces the challenge of scaling the business to manage an unprecedented number of commercially secured growth projects. The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources, in-service delays and increasing complexity of projects (collectively, Execution Risk).

Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation and environmental and regulatory permitting. Cost escalations or missed in-service dates on future projects may impact future earnings and cash flows and may hinder the Company's ability to secure future projects. Construction delays due to regulatory delays, third-party opposition, contractor or supplier non-performance and weather conditions may impact project development.

The Company strives to be an industry leader in project execution through Major Projects and through this group the Company aims to mitigate project execution risk. Major Projects is centralized and has a clearly defined governance structure and process for all major projects, with dedicated resources organized to lead and execute each major project.

Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors and those selected are chosen based on the Company's strict adherence to safety including robust safety standards embedded in contracts with suppliers. The Company has assessed work volumes for the next several years across its major projects to optimize the expected costs, supply of services, material and labour to execute the projects. Underpinning this approach is Major Project's Project Lifecycle Gating Control tool which helps to ensure schedule, cost, safety and quality objectives are on track and met for each stage of a project's development and construction.

Consultations with regulators are held in-advance of project construction to enhance understanding of project rationale and ensure applications are compliant and robust, while at all times maintaining a strong focus on integrity and public safety. The Company also actively involves its legal and regulatory teams to work closely with Major Projects to engage in open dialogue with government agencies, regulators, land owners, Aboriginal groups and special interest groups to identify and develop appropriate responses to their concerns regarding the Company's projects.

Planning and Investment Analysis

The Company evaluates expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, change in cost estimates, project scoping and risk assessment could result in a loss in profits for the Company. Large scale acquisitions may involve significant pricing and integration risk.

The planning and investment analysis process involves all levels of management and Board of Directors' review to ensure alignment across the Company. A centralized corporate development group rigorously evaluates all major investment proposals with consistent due diligence processes, including a thorough review of the asset quality, systems and financial performance of the assets being assessed.

Human Resources

Like many other companies in the energy sector, Enbridge faces a risk that it will be unable to attract and retain the necessary skilled people resources to fulfill its growth plan. Factors that could impact Enbridge's ability to secure these resources include labour shortages and the shortage of technically skilled workers; rates of retirement and turnover and the ability to successfully transfer knowledge; and retaining Enbridge's reputation as a great employer. As the Company continues through a sustained period of growth, attracting and retaining adequate personnel who adhere to Enbridge's values will be critical to achieving the Company's growth plan.

Operational and Economic Regulation

Many of the Company's operations are regulated and are subject to both operational and economic regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur.

Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs. Regulatory scrutiny over the Company's assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on the Company's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Company.

The Company also faces economic regulatory risk. Broadly defined, economic regulation risk is the risk regulators or other government entities change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on the Company's revenues and earnings. Delays in regulatory approvals could result in cost escalations and constructions delays, which also negatively impact the Company's operations.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of its operations. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls for these assets. Enbridge retains dedicated professional staff and maintains strong relationships with customers, intervenors and regulators to help minimize economic regulation risk. However, despite the best efforts on the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Operational Risks

Environmental Incident

An environmental incident could have lasting reputational impacts to Enbridge and could impact its ability to work with various stakeholders. In addition to the cost of remediation activities (to the extent not covered by insurance), environmental incidents may lead to an increased cost of operating and insuring the Company's assets, thereby negatively impacting earnings. The Company mitigates risk of environmental incidents through its ORM Plan, which broadly aims to position Enbridge as the industry leader for system integrity, environmental and safety programs. Mitigation efforts continue to focus on efforts to reduce the likelihood of an environmental incident. Under the umbrella of the ORM Plan the Company has continued its maintenance, excavation and repair program which is supported by operating and capital budgets for pipeline integrity. The Company's $7.5 billion L3R Program, the largest project in the Company's history, is a further commitment by the Company to its key strategic priority of safety and operational reliability. Once it is completed, the L3R Program will provide a major enhancement to Enbridge's mainline system by replacing most segments of the Line 3 pipeline with the latest high-strength steel and coating.

Although the Company believes its integrated management system, plans and processes mitigate the risk of environmental incidents, there remains a chance that an environmental incident could occur. The ORM plan also seeks to mitigate the severity of a potential environmental incident through continued process improvements and enhancements in leak detection processes and alarm analysis procedures. The Company has also invested significant resources to enhance its emergency response plans, operator training and landowner education programs to address any potential environmental incident.

The Company maintains comprehensive insurance coverage for its subsidiaries and affiliates that it renews annually. The insurance program includes coverage for commercial liability that is considered customary for its industry and includes coverage for environmental incidents. The total insurance coverage will be allocated on an equitable basis in the unlikely event multiple insurable incidents exceeding the Company's coverage limits are experienced by Enbridge and two Enbridge subsidiaries covered by the same policy within the same insurance period.

Public, Worker and Contractor Safety

Several of the Company's pipeline systems run adjacent to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company's assets. In addition, given the natural hazards inherent in Enbridge's operations, its workers and contractors are subject to personal safety risks.

Safety and operational reliability are the most important priorities at Enbridge. Enbridge's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its ORM Plan and emergency response preparedness, as described above in *Environmental Incident.* The Company also actively engages stakeholders through public safety awareness activities to ensure the public is aware of potential hazards and understands the appropriate actions to take in the event of an emergency. Enbridge also actively engages first responders through education programs that endeavour to equip first responders with the skills and tools to safely and effectively respond to a potential incident.

Finally, Enbridge believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents. For employees, safety objectives have been incorporated across all levels of the Company and are included as part of an employee's compensation measures. Contractors are chosen following a rigorous selection process that includes a strict adherence to Enbridge's safety culture.

Service Interruption Incident

A service interruption due to a major power disruption or curtailment on commodity supply could have a significant impact on the Company's ability to operate its assets and negatively impact future earnings, relationships with stakeholders and the Company's reputation. Specifically, for Gas Distribution, any prolonged interruptions would ultimately impact gas distribution customers. Service interruptions that impact the Company's crude oil transportation services can negatively impact shippers' operations and earnings as they are dependent on Enbridge services to move their product to market or fulfill their own contractual arrangements. The Company mitigates service interruption risk through its diversified sources of supply, storage withdrawal flexibility, backup power systems, critical parts inventory and redundancies for critical equipment. Specifically for Gas Distribution, the GTA reinforcement project, which is expected to be completed in late 2015, will be a key mitigation as the project will provide significant diversification of gas supply to EGD's distribution network and will further reduce the likelihood of a service interruption incident.

Information Technology Security or Systems Incident

The Company's infrastructure, applications and data are becoming more integrated, creating an increased risk that failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems and intellectual property. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems which could impact pipeline operations. A successful cyber-attack could also lead to a large scale data breach resulting in unauthorized disclosure, corruption or loss of sensitive company or customer information. The Company has implemented a comprehensive security strategy that includes a security policy and standards framework, defined governance and oversight, layered access controls, continuous monitoring, infrastructure and network security and threat detection and incident response through a security operations centre. The Company's information technology security operations are consolidated under one leadership structure to increase consistency and compliance with the Company's security requirements across business segments.

Business Environment Risks

Aboriginal Relations

Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal people when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights. Crown consultation has the potential to delay regulatory approval processes and construction, which may affect project economics. In some cases, respecting Aboriginal rights may mean regulatory approval is denied or the conditions in the approval make a project economically challenging.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has implemented an Aboriginal and Native American Policy. This Policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the Policy sets out principles governing the Company's relationships with Aboriginal and Native American people and makes commitments to work with Aboriginal people and Native Americans so they may realize benefits from the Company's projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal and Native American relations on Enbridge's operations and development initiatives is uncertain.

Special Interest Groups including Non-Governmental Organizations

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups, including non-governmental organizations. Recent judicial decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, the Company and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil sands development and shipment of production from oil sands regions.

The Company works proactively with special interest groups and non-governmental organizations to identify and develop appropriate responses to their concerns regarding its projects. The Company is investing significant resources in these areas. Its CSR program also reports on the Company's responsiveness to environmental and community issues. Refer to Enbridge's annual CSR Report, available online at http://csr.enbridge.com for further details regarding the CSR program. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of this MD&A.***

CRITICAL ACCOUNTING ESTIMATES

The following critical accounting estimates discussed below have an impact across the various segments of the Company.

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2014 of $53,830 million (2013 - $42,279 million), or 73.9% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

ASSET IMPAIRMENT

The Company evaluates the recoverability of its property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes or other factors indicate it may not recover the carrying amount of the assets. The Company continually monitors its businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the AER and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expense in operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. As at December 31, 2014, the Company's significant regulatory assets totalled $2,160 million (2013 - $1,138 million) and significant regulatory liabilities totalled $962 million (2013 - $1,016 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and OPEB to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the universal method. This method involves complex actuarial calculations using several assumptions including discount rates, which were determined by referring to high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The actual return on plan assets exceeded the expected return on plan assets by $58 million for the year ended December 31, 2014 (2013 - $101 million) as disclosed in Note 25, Retirement and Postretirement Benefits, to the 2014 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2014 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	205	21	18	-
Decrease in expected return on assets	-	9	-	-
Decrease in rate of salary increase	(44)	(9)	-	-

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments are detailed in Note 29, Commitments and Contingencies, of the 2014 Annual Consolidated Financial Statements. In addition, any unasserted claims that later may become evident could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments.

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 EPI 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 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 began 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 $177 million. Of this amount, $74 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System 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 consolidated financial statements as a result of adopting this update.

Pushdown Accounting for Business Combinations

Effective November 18, 2014, the Company prospectively adopted ASU 2014-17 which provides an acquired entity with the option to apply pushdown accounting in its separate financial statements upon the occurrence of a change-in-control event. There was no impact to the consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items

ASU 2015-01 was issued in January 2015 and eliminates the concept of extraordinary items from GAAP. Entities will no longer be required to separately classify and present extraordinary events in the income statement, net of tax, after income from continuing operations. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Hybrid Financial Instruments Issued in the Form of a Share
ASU 2014-16 was issued in November 2014 with the intent to eliminate the use of different methods in practice in the accounting for hybrid financial instruments issued in the form of a share. The new standard clarifies the evaluation of the economic characteristics and risks of a host contract in these hybrid financial instruments. The Company is currently assessing the impact of the new standard on its consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2015 and is to be applied on a modified retrospective basis.

Development Stage Entities
ASU 2014-10, issued in June 2014, eliminates the concept of a development stage entity from U.S. GAAP and removes the related incremental reporting requirements. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and is not expected to have a material impact on the Company's consolidated financial statements. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the variable interest entity model and evaluating the sufficiency of equity at risk. The Company is currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

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.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As at December 31, 2014, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

Management's Report on Internal Control over Financial Reporting
Management of Enbridge is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.
Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2014, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2014.

During the year ended December 31, 2014, there has been no material change in the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as at December 31, 2014 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

ENBRIDGE

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2014

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and independent auditors have unrestricted access to the AF&RC.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and to provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2014, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2014.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company and its internal control over financial reporting in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

"signed"

Al Monaco
President & Chief Executive Officer

"signed"

John K. Whelen
Executive Vice President &
Chief Financial Officer

February 19, 2015

Independent Auditor’s Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.’s 2014, 2013 and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management’s responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2014 and December 31, 2013 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014 in accordance with accounting principles generally accepted in the United States of America.

Report on internal control over financial reporting
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

Auditor's responsibility
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 19, 2015

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**28,281**	26,039	18,494
Gas distribution sales	**2,853**	2,265	1,910
Transportation and other services	**6,507**	4,614	4,256
	37,641	32,918	24,660
Expenses			
Commodity costs	**27,504**	25,222	17,959
Gas distribution costs	**1,979**	1,585	1,220
Operating and administrative	**3,281**	3,014	2,739
Depreciation and amortization	**1,577**	1,370	1,236
Environmental costs, net of recoveries	**100**	362	(88)
	34,441	31,553	23,066
	3,200	1,365	1,594
Income from equity investments *(Note 11)*	**368**	330	195
Other income/(expense) *(Note 26)*	**(266)**	(135)	238
Interest expense *(Note 16)*	**(1,129)**	(947)	(841)
	2,173	613	1,186
Income taxes *(Note 24)*	**(611)**	(123)	(171)
Earnings from continuing operations	**1,562**	490	1,015
Discontinued operations *(Note 9)*			
Earnings/(loss) from discontinued operations before income taxes	**73**	6	(123)
Income taxes (expense)/recovery from discontinued operations	**(27)**	(2)	44
Earnings/(loss) from discontinued operations	**46**	4	(79)
Earnings	**1,608**	494	936
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(203)**	135	(229)
Earnings attributable to Enbridge Inc.	**1,405**	629	707
Preference share dividends	**(251)**	(183)	(105)
Earnings attributable to Enbridge Inc. common shareholders	**1,154**	446	602
Earnings attributable to Enbridge Inc. common shareholders			
Earnings from continuing operations	**1,108**	442	681
Earnings/(loss) from discontinued operations, net of tax	**46**	4	(79)
	1,154	446	602
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**1.34**	0.55	0.88
Discontinued operations	**0.05**	-	(0.10)
	1.39	0.55	0.78
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**1.32**	0.55	0.87
Discontinued operations	**0.05**	-	(0.10)
	1.37	0.55	0.77

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings	**1,608**	494	936
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(833)**	697	(176)
Change in unrealized gains/(loss) on net investment hedges	**(270)**	(96)	13
Other comprehensive income from equity investees	**10**	11	2
Reclassification to earnings of realized cash flow hedges	**76**	72	7
Reclassification to earnings of unrealized cash flow hedges	**158**	39	20
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	**15**	27	18
Actuarial gains/(loss) on pension plans and other postretirement benefits	**(191)**	114	(56)
Change in foreign currency translation adjustment	**1,238**	710	(158)
Other comprehensive income/(loss)	**203**	1,574	(330)
Comprehensive income	**1,811**	2,068	606
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(242)**	(276)	(165)
Comprehensive income attributable to Enbridge Inc.	**1,569**	1,792	441
Preference share dividends	**(251)**	(183)	(105)
Comprehensive income attributable to Enbridge Inc. common shareholders	**1,318**	1,609	336

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**5,141**	3,707	1,056
Preference shares issued	**1,374**	1,434	2,651
Balance at end of year	**6,515**	5,141	3,707
Common shares *(Note 20)*			
Balance at beginning of year	**5,744**	4,732	3,969
Common shares issued	**446**	582	388
Dividend reinvestment and share purchase plan	**428**	361	297
Shares issued on exercise of stock options	**51**	69	78
Balance at end of year	**6,669**	5,744	4,732
Additional paid-in capital			
Balance at beginning of year	**746**	522	242
Stock-based compensation	**31**	28	26
Options exercised	**(14)**	(17)	(17)
Issuance of treasury stock *(Note 11)*	**22**	208	236
Enbridge Energy Partners, L.P. equity restructuring *(Note 19)*	**1,601**	-	-
Transfer of interest to Enbridge Income Fund	**176**	-	-
Drop down of interest to Midcoast Energy Partners, L.P.	**(18)**	-	-
Dilution gains and other	**5**	5	35
Balance at end of year	**2,549**	746	522
Retained earnings			
Balance at beginning of year	**2,550**	3,173	3,643
Earnings attributable to Enbridge Inc.	**1,405**	629	707
Preference share dividends	**(251)**	(183)	(105)
Common share dividends declared	**(1,177)**	(1,035)	(895)
Dividends paid to reciprocal shareholder	**17**	19	20
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 19)*	**(973)**	(53)	(197)
Balance at end of year	**1,571**	2,550	3,173
Accumulated other comprehensive loss *(Note 22)*			
Balance at beginning of year	**(599)**	(1,762)	(1,496)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**164**	1,163	(266)
Balance at end of year	**(435)**	(599)	(1,762)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(86)**	(126)	(187)
Issuance of treasury stock	**3**	40	61
Balance at end of year	**(83)**	(86)	(126)
Total Enbridge Inc. shareholders' equity	**16,786**	13,496	10,246
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**4,014**	3,258	3,141
Earnings/(loss) attributable to noncontrolling interests	**214**	(111)	241
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(192)**	166	(39)
Change in foreign currency translation adjustment	**146**	223	(60)
Reclassification to earnings of realized cash flow hedges	**18**	4	23
Reclassification to earnings of unrealized cash flow hedges	**77**	14	13
	49	407	(63)
Comprehensive income attributable to noncontrolling interests	**263**	296	178
Distributions *(Note 19)*	**(535)**	(468)	(421)
Contributions *(Note 19)*	**212**	922	382
Dilution gains	**-**	-	6
Acquisitions *(Note 6)*	**351**	-	(25)
Enbridge Energy Partners, L.P. equity restructuring *(Note 19)*	**(2,330)**	-	-
Drop down of interest to Midcoast Energy Partners, L.P. *(Note 19)*	**39**	-	-
Other	**1**	6	(3)
Balance at end of year	**2,015**	4,014	3,258
Total equity	**18,801**	17,510	13,504
Dividends paid per common share	**1.40**	1.26	1.13

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Operating activities			
Earnings	**1,608**	494	936
(Earnings)/loss from discontinued operations	**(46)**	(4)	79
Depreciation and amortization	**1,577**	1,370	1,236
Deferred income taxes *(Note 24)*	**587**	131	3
Changes in unrealized (gains)/loss on derivative instruments, net	**(96)**	1,262	665
Cash distributions in excess of equity earnings	**196**	355	439
Impairment	**18**	6	39
Gain on disposition *(Note 6)*	**(38)**	(18)	-
Hedge ineffectiveness *(Note 23)*	**210**	48	20
Inventory revaluation allowance *(Note 8)*	**174**	4	10
Other	**115**	(43)	79
Changes in regulatory assets and liabilities	**22**	(11)	44
Changes in environmental liabilities, net of recoveries	**(78)**	148	(26)
Changes in operating assets and liabilities *(Note 27)*	**(1,721)**	(409)	(660)
Cash provided by continuing operations	**2,528**	3,333	2,864
Cash provided by discontinued operations *(Note 9)*	**19**	8	10
	2,547	3,341	2,874
Investing activities			
Additions to property, plant and equipment	**(10,524)**	(8,235)	(5,194)
Long-term investments	**(854)**	(1,018)	(531)
Additions to intangible assets	**(208)**	(212)	(163)
Acquisitions*)*	**(394)**	-	(340)
Proceeds from disposition	**85**	41	18
Affiliate loans, net	**13**	8	8
Changes in restricted cash	**(13)**	(15)	(2)
Cash used in continuing operations	**(11,895)**	(9,431)	(6,204)
Cash provided by discontinued operations *(Note 9)*	**4**	-	-
	(11,891)	(9,431)	(6,204)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**734**	(350)	412
Net change in commercial paper and credit facility draws	**4,212**	1,562	(294)
Southern Lights project financing repayments	**(1,519)**	(5)	(13)
Debenture and term note issues - Southern Lights	**1,507**	-	-
Debenture and term note issues	**5,414**	2,845	2,199
Debenture and term note repayments	**(1,348)**	(660)	(349)
Repayment of acquired debt	**-**	-	(160)
Contributions from noncontrolling interests	**212**	922	448
Distributions to noncontrolling interests	**(535)**	(468)	(421)
Contributions from redeemable noncontrolling interests	**323**	92	213
Distributions to redeemable noncontrolling interests	**(79)**	(72)	(49)
Preference shares issued	**1,365**	1,428	2,634
Common shares issued	**478**	628	465
Preference share dividends	**(245)**	(178)	(93)
Common share dividends	**(749)**	(674)	(597)
	9,770	5,070	4,395
Effect of translation of foreign denominated cash and cash equivalents	**59**	20	(12)
Increase/(decrease) in cash and cash equivalents	**485**	(1,000)	1,053
Cash and cash equivalents at beginning of year - continuing operations	**756**	1,776	723
Cash and cash equivalents at beginning of year - discontinued operations	**20**	-	-
Cash and cash equivalents at end of year	**1,261**	776	1,776
Cash and cash equivalents - discontinued operations	**-**	(20)	-
Cash and cash equivalents - continuing operations	**1,261**	756	1,776
Supplementary cash flow information			
Income taxes paid	**9**	107	267
Interest paid	**1,435**	1,097	988

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2014**	2013
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,261**	756
Restricted cash	**47**	34
Accounts receivable and other *(Note 7)*	**5,504**	4,956
Accounts receivable from affiliates	**241**	65
Inventory *(Note 8)*	**1,148**	1,115
Assets held for sale *(Note 9)*	**-**	24
	8,201	6,950
Property, plant and equipment, net *(Note 9)*	**53,830**	42,279
Long-term investments *(Note 11)*	**5,408**	4,212
Deferred amounts and other assets *(Note 12)*	**3,208**	2,662
Intangible assets, net *(Note 13)*	**1,166**	1,004
Goodwill *(Note 14)*	**483**	445
Deferred income taxes *(Note 24)*	**561**	16
	72,857	57,568
Liabilities and equity		
Current liabilities		
Bank indebtedness	**507**	338
Short-term borrowings *(Note 16)*	**1,041**	374
Accounts payable and other *(Note 15)*	**6,444**	6,664
Accounts payable to affiliates	**80**	46
Interest payable	**264**	228
Environmental liabilities	**161**	260
Current maturities of long-term debt *(Note 16)*	**1,004**	2,811
Liabilities held for sale *(Note 9)*	**-**	7
	9,501	10,728
Long-term debt *(Note 16)*	**33,423**	22,357
Other long-term liabilities *(Note 17)*	**4,041**	2,938
Deferred income taxes *(Note 24)*	**4,842**	2,925
Liabilities held for sale *(Note 9)*	**-**	57
	51,807	39,005
Commitments and contingencies *(Note 29)*		
Redeemable noncontrolling interests *(Note 19)*	**2,249**	1,053
Equity		
Share capital *(Note 20)*		
Preference shares	**6,515**	5,141
Common shares (852 and 831 outstanding at December 31, 2014 and 2013, respectively)	**6,669**	5,744
Additional paid-in capital	**2,549**	746
Retained earnings	**1,571**	2,550
Accumulated other comprehensive loss *(Note 22)*	**(435)**	(599)
Reciprocal shareholding *(Note 11)*	**(83)**	(86)
Total Enbridge Inc. shareholders' equity	**16,786**	13,496
Noncontrolling interests *(Note 19)*	**2,015**	4,014
	18,801	17,510
	72,857	57,568

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

"signed"
David A. Arledge
Chair

"signed"
J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Seaway Crude Pipeline System (Seaway Pipeline) and Flanagan South Pipeline, Southern Lights Pipeline, Spearhead Pipeline and Feeder Pipelines and Other.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, gathering and processing facilities and the Company's energy services businesses, along with renewable energy and transmission facilities.

Investments in natural gas pipelines include the Company's interests in the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance Pipeline and Canadian Midstream assets located in northeast British Columbia and northwest Alberta. The energy services businesses undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on Alliance Pipeline, Vector and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 33.7% (2013 - 20.6%) economic interest in Enbridge Energy Partners, L.P. (EEP) and Enbridge's interests in both the Eastern Access and Lakehead System Mainline Expansion projects held through Enbridge Energy, Limited Partnership. Also within Sponsored Investments is the Company's overall 66.4% (2013 - 67.3%) economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge, through its subsidiaries, manages the day-to-day operations of and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines, including the Lakehead Pipeline System (Lakehead System), which is the United States portion of the Enbridge mainline system, and transports, gathers, processes and markets natural gas and NGL. The primary operations of the Fund include renewable power generation, crude oil and liquids pipeline, including interests in Southern Lights Pipeline, and storage businesses in western Canada and a 50% interest in the Alliance Pipeline.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, general corporate investments and financing costs not allocated to the business segments.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities and Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; fair value of asset retirement obligations (ARO) *(Note 18)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Note 23)*; provisions for income taxes *(Note 24)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 25)*; commitments and contingencies *(Note 29)*; and estimates of losses related to environmental remediation obligations *(Note 29)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and variable interest entities for which the Company is the primary beneficiary. Upon inception of a contractual agreement, the Company performs an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a variable interest entity (VIE). Where the Company concludes it is the primary beneficiary of a VIE, the Company will consolidate the accounts of that entity. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where the Company retains an undivided interest in assets and liabilities, Enbridge records its proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which the Company exercises significant influence are accounted for using the equity method.

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 5)*.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. The Company recognizes revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require the Company to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay the Company a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. From July 1, 2011 onward, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, the Company prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenues are recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area.

For natural gas and marketing businesses, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges at December 31, 2014, 2013 or 2012.

Net Investment Hedges

Gains and losses arising from translation of net investment in foreign operations from their functional currencies to the Company's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA). The Company designates foreign currency derivatives and United States dollar denominated debt as hedges of net investments in United States dollar denominated foreign operations. As a result, the effective portion of the change in the fair value of the foreign currency derivatives as well as the translation of United States dollar denominated debt are reflected in OCI and any ineffectiveness is reflected in current period earnings. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from disposal of a foreign operation.

Classification of Derivatives

The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs as Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS

Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, the Company capitalizes interest costs associated with its investment during such period.

OTHER INVESTMENTS

Generally, the Company classifies equity investments in entities over which it does not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are classified as available for sale investments measured at fair value through OCI. Dividends received from investments carried at cost are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS

Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity not owned by the Company in such entities is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund's noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

INCOME TAXES

The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar presentation currency are included in the cumulative translation adjustment component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY

Inventory is comprised of natural gas in storage held in EGD and crude oil and natural gas held primarily by energy services businesses in the Gas Pipelines, Processing and Energy Services and Sponsored Investments segments. Natural gas in storage in EGD is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs on the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt and are recorded in Interest expense.

INTANGIBLE ASSETS
Intangible assets consist primarily of acquired long-term transportation or power purchase agreements, natural gas supply opportunities and certain software costs. Natural gas supply opportunities are growth opportunities, identified upon acquisition, present in gas producing zones where certain of EEP's gas systems are located. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Company's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

IMPAIRMENT
The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or 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.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality tables were issued by the Society of Actuaries in the United States. These new tables, along with the Canadian Institute of Actuaries tables that were revised in 2013, were used by the Company for measurement of its December 31, 2014 benefit obligations of its United States pension plan (the United States Plan) and the Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans), respectively. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates for its Canadian Plans, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets, Accounts payable and other or Other long-term liabilities, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

Certain regulated utility operations of the Company expect to recover pension expense in future rates and therefore record a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to EGD's OPEB obligation was not recorded given recovery in rates was not probable. Commencing in 2012, pursuant to a specific rate order allowing EGD to recover OPEB costs determined on an accrual basis in rates, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance based stock options (PBSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PBSO granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period with a corresponding credit to Additional paid-in capital. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSU vest at the completion of a three-year term and RSU vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSU is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

The Company expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. The Company expenses costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. The Company records liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. The Company's estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. The Company evaluates recoveries from insurance coverage separately from the liability and, when recovery is probable, the Company records and reports an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. 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 consolidated financial statements as a result of adopting this update.

Pushdown Accounting for Business Combinations

Effective November 18, 2014, the Company prospectively adopted ASU 2014-17 which provides an acquired entity with the option to apply pushdown accounting in its separate financial statements upon the occurrence of a change-in-control event. There was no impact to the consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items

ASU 2015-01 was issued in January 2015 and eliminates the concept of extraordinary items from U.S. GAAP. Entities will no longer be required to separately classify and present extraordinary items in the income statement. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Hybrid Financial Instruments Issued in the Form of a Share

ASU 2014-16 was issued in November 2014 with the intent to eliminate the use of different methods in practice in the accounting for hybrid financial instruments issued in the form of a share. The new standard clarifies the evaluation of the economic characteristics and risks of a host contract in these hybrid financial instruments. The Company is currently assessing the impact of the new standard on its consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2015 and is to be applied on a modified retrospective basis.

Development Stage Entities

ASU 2014-10, issued in June 2014, eliminates the concept of a development stage entity from U.S. GAAP and removes the related incremental reporting requirements. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and is not expected to have a material impact on the Company's consolidated financial statements. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. The Company is currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

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.

4. SEGMENTED INFORMATION

Year ended December 31, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services[2]	Sponsored Investments[2]	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**2,283**	**3,216**	**23,023**	**9,119**	**-**	**37,641**
Commodity and gas distribution costs	**-**	**(1,979)**	**(21,921)**	**(5,583)**	**-**	**(29,483)**
Operating and administrative	**(1,101)**	**(530)**	**(175)**	**(1,438)**	**(37)**	**(3,281)**
Depreciation and amortization	**(498)**	**(304)**	**(114)**	**(642)**	**(19)**	**(1,577)**
Environmental costs, net of recoveries	**7**	**-**	**-**	**(107)**	**-**	**(100)**
	691	**403**	**813**	**1,349**	**(56)**	**3,200**
Income/(loss) from equity investments	**160**	**-**	**136**	**86**	**(14)**	**368**
Other income/(expense)	**12**	**(8)**	**38**	**5**	**(313)**	**(266)**
Interest income/(expense)	**(372)**	**(165)**	**(98)**	**(559)**	**65**	**(1,129)**
Income taxes recovery/(expense)	**(24)**	**(17)**	**(318)**	**(263)**	**11**	**(611)**
Earnings/(loss) from continuing operations	**467**	**213**	**571**	**618**	**(307)**	**1,562**
Discontinued operations						
Earnings from discontinued operations before income taxes	**-**	**-**	**73**	**-**	**-**	**73**
Income taxes from discontinued operations	**-**	**-**	**(27)**	**-**	**-**	**(27)**
Earnings from discontinued operations	**-**	**-**	**46**	**-**	**-**	**46**
Earnings/(loss)	**467**	**213**	**617**	**618**	**(307)**	**1,608**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(4)**	**-**	**-**	**(199)**	**-**	**(203)**
Preference share dividends	**-**	**-**	**-**	**-**	**(251)**	**(251)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**463**	**213**	**617**	**419**	**(558)**	**1,154**
Additions to property, plant and equipment[5]	**5,917**	**603**	**678**	**3,269**	**60**	**10,527**
Total assets	**27,657**	**9,320**	**7,601**	**23,515**	**4,764**	**72,857**

Year ended December 31, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services[2]	Sponsored Investments[2]	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	2,272	2,741	20,310	7,595	-	32,918
Commodity and gas distribution costs	-	(1,585)	(20,244)	(4,978)	-	(26,807)
Operating and administrative	(1,006)	(534)	(221)	(1,226)	(27)	(3,014)
Depreciation and amortization	(429)	(321)	(75)	(530)	(15)	(1,370)
Environmental costs, net of recoveries	(79)	-	-	(283)	-	(362)
	758	301	(230)	578	(42)	1,365
Income from equity investments	118	-	154	56	2	330
Other income/(expense)	39	20	39	37	(270)	(135)
Interest income/(expense)	(319)	(160)	(81)	(409)	22	(947)
Income taxes recovery/(expense)	(165)	(32)	50	(133)	157	(123)
Earnings/(loss) from continuing operations	431	129	(68)	129	(131)	490
Discontinued operations						
Earnings from discontinued operations before income taxes	-	-	6	-	-	6
Income taxes from discontinued operations	-	-	(2)	-	-	(2)
Earnings from discontinued operations	-	-	4	-	-	4
Earnings/(loss)	431	129	(64)	129	(131)	494
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	-	139	-	135
Preference share dividends	-	-	-	-	(183)	(183)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	427	129	(64)	268	(314)	446
Additions to property, plant and equipment[5]	4,360	533	744	2,565	34	8,236
Total assets	20,950	7,942	7,015	18,527	3,134	57,568

Year ended December 31, 2012	Liquids Pipelines[3]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3,4]	Sponsored Investments[2,3]	Corporate[1,4]	Consolidated
(millions of Canadian dollars)						
Revenues	2,445	2,438	13,106	6,671	-	24,660
Commodity and gas distribution costs	-	(1,220)	(13,676)	(4,283)	-	(19,179)
Operating and administrative	(942)	(528)	(142)	(1,076)	(51)	(2,739)
Depreciation and amortization	(399)	(336)	(57)	(431)	(13)	(1,236)
Environmental costs, net of recoveries	-	-	-	88	-	88
	1,104	354	(769)	969	(64)	1,594
Income/(loss) from equity investments	46	-	141	55	(47)	195
Other income/(expense)	(7)	83	33	49	80	238
Interest income/(expense)	(250)	(164)	(50)	(397)	20	(841)
Income taxes recovery/(expense)	(192)	(66)	269	(169)	(13)	(171)
Earnings/(loss) from continuing operations	701	207	(376)	507	(24)	1,015
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(123)	-	-	(123)
Income taxes recovery from discontinued operations	-	-	44	-	-	44
Loss from discontinued operations	-	-	(79)	-	-	(79)
Earnings/(loss)	701	207	(455)	507	(24)	936
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	(1)	(224)	-	(229)
Preference share dividends	-	-	-	-	(105)	(105)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	697	207	(456)	283	(129)	602
Additions to property, plant and equipment[5]	1,927	445	933	1,886	4	5,195

1 Included within the Corporate segment was Interest income of $694 million (2013 - $443 million; 2012 - $336 million) charged to other operating segments.

2 In November 2014, Enbridge's 50% interest in the United States portion of Alliance Pipeline (Alliance Pipeline US) was transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $41 million (2013 - $43 million; 2012 - $39 million) have not been reclassified between segments for presentation purposes.

3 In December 2012, certain crude oil storage and renewable energy assets were transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $33 million have not been reclassified among *segments for presentation purposes.*

4 *Due to a change in organizational structure effective January 1, 2013, for the year ended December 31, 2012 earnings of $1 million and additions to property, plant and equipment of $108 million were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.*

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

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Canada	**14,963**	12,690	11,629
United States	**22,678**	20,228	13,031
	37,641	32,918	24,660

1 *Revenues are based on the country of origin of the product or service sold.*

Property, Plant and Equipment

December 31,	**2014**	2013
(millions of Canadian dollars)		
Canada	**27,420**	22,865
United States	**26,410**	19,414
	53,830	42,279

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation. The Company's significant regulated businesses and related accounting impacts are described below.

Canadian Mainline

Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on the Lakehead System and delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with NEB guidelines, was approved by the NEB in June 2011 and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a NEB rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The United States portion of the Southern Lights Pipeline (Southern Lights US) is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline (Southern Lights Canada) is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. For the year ended December 31, 2014, rates were set under the customized incentive rate plan (the IR Plan) approved by the OEB, with modifications, for 2014 through 2018, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE.

The OEB approved final 2014 rates to be implemented with an effective date of January 1, 2014. Within annual rate proceedings for 2015 through 2018, the IR Plan requires allowed revenues, and corresponding rates, to be updated annually for select items. The OEB also approved the adoption of a new approach for determining net salvage percentages to be included within EGD's approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves. The IR Plan includes an earnings sharing mechanism, whereby any return over the allowed rate of return for a given year under the IR Plan will be shared equally with customers.

For the year ended December 31, 2013, rates were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed ROE. The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories. The earnings sharing mechanism, which was previously in effect under revenue cap incentive regulation (IR), did not apply to the 2013 Settlement.

The 2013 Settlement allowed EGD to recognize revenue and a corresponding regulatory asset relating to OPEB as it established the right to recover previous OPEB costs of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The gain was presented within Other income/(expense) on the Consolidated Statements of Earnings for the year ended December 31, 2012 *(Note 26)*. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

Prior to 2013, EGD operated under an IR mechanism, calculated on a revenue per customer basis, with the OEB for a five-year period between 2008 and 2012. Under the IR mechanism, the Company was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

EGD's after-tax rate of return on common equity embedded in rates was 9.4% for the year ended December 31, 2014 (2013 - 8.9%) based on a 36% (2013 - 36%) deemed common equity component of capital for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick is regulated by the EUB and currently sets tolls at the lower of market-based or cost of service rates.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	**907**	727
Tolling deferrals[2]	**(39)**	(36)
Recoverable income taxes[3]	**46**	42
Gas Distribution		
Deferred income taxes[4]	**275**	214
Purchased gas variance[5]	**673**	-
Pension plans and OPEB[6]	**171**	94
Constant dollar net salvage adjustment[7]	**37**	-
Future removal and site restoration reserves[8]	**(562)**	(929)
Site restoration[9]	**(283)**	-
Revenue adjustment[10]	**(52)**	-
Transaction services deferral[11]	**(26)**	(51)
Sponsored Investments		
Deferred income taxes[1]	**15**	28
Transportation revenue adjustments[12]	**36**	33

1 The asset represents the regulatory offset to deferred income tax liabilities that are expected to be recovered under flow-through income tax treatment. The recovery period depends on future reversal of temporary differences.

2 The liability reflects net tax benefits expected to be refunded through future transportation tolls on Southern Lights Canada. The balance is expected to accumulate for approximately eight years before being refunded through tolls.

3 The asset represents future revenues to be collected from shippers for Southern Lights US to recover federal income taxes payable on the equity component of AFUDC. The recovery period is approximately 30 years.

4 The asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred income taxes are expected to be recovered or refunded through regulator-approved rates. The recovery period depends on future temporary differences. Deferred income taxes in Gas Distribution are excluded from the rate base and do not earn an ROE.

5 The purchased gas variance (PGVA) balance represents the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016.

6 The pension plans and OPEB balances represent the regulatory offset to pension plan and OPEB obligations to the extent the amounts are expected to be collected from customers in future rates. An OPEB balance of $89 million is being collected over a 20-year period that commenced in 2013, whereas the settlement period for the pension regulatory asset is not determinable. The balances are excluded from the rate base and do not earn an ROE.

7 The constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the Site restoration adjustment.

8 The future removal and site restoration reserves balance results from amounts collected from customers by certain businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred.

9 The site restoration clearance adjustment represents the amount that was determined by the OEB, of previously collected costs for future removal and site restoration that is considered to be in excess of future requirements and will be refunded to customers over the term of the IR Plan. This was a result of the OEB's approval of the adoption of a new approach for determining net salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves.

10 The revenue adjustment represents the revenue variance between interim rates, which were in place from January 1, 2014 to September 30, 2014, and the final OEB approved 2014 rates, which were implemented on October 1, 2014, but effective January 1, 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount to be refunded to customers.

11 The transaction services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. The balance is expected to be refunded to customers in the following year.

12 Transportation revenue adjustments are the cumulative differences between actual expenses incurred and estimated expenses included in transportation tolls. Transportation revenue adjustments are not included in the rate base. The recovery period is approximately five years and dependent on shipper throughput levels.

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2014, cumulative costs relating to this consulting contract of $166 million (2013 - $154 million) were included in Property, plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Magic Valley and Wildcat Wind Farms

On December 31, 2014, Enbridge acquired an 80% controlling interest in Magic Valley, a wind farm located in Texas and Wildcat, a wind farm located in Indiana for cash consideration of $394 million (US$340 million). No revenue or earnings were recognized in the year ended December 31, 2014 as the wind farms were acquired on December 31, 2014. The wind farms are included within the Gas Pipelines, Processing and Energy Services segment.

If the acquisition had occurred on January 1, 2013, revenues and earnings for the year ended December 31, 2014 would have increased by $64 million (US$58 million) and $8 million (US$7 million), respectively, and revenues and earnings for the year ended December 31, 2013 would have increased by $44 million (US$43 million) and decreased by $2 million (US$2 million), respectively.

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

December 31,	**2014**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	747
Intangible assets	12
Other long-term liabilities	(14)
Noncontrolling interests[1]	(351)
	394
Purchase price:	
Cash	394

1 *The fair value of the noncontrolling interests was determined using a combination of the implied purchase price for the remaining 20% interest and discounted cash flow models.*

Silver State North Solar Project

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada for cash consideration of $195 million (US$190 million). Silver State expanded the Company's renewable energy business. Revenues and earnings of $10 million and $1 million, respectively, were recognized in the year ended December 31, 2012. No revenues or earnings were recognized in any prior period as the solar project commenced operations in the second quarter of 2012. Silver State is included within the Gas Pipelines, Processing and Energy Services segment.

March 22,	2012
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Accounts receivable and other[1]	54
Property, plant and equipment	141
	195
Purchase price:	
Cash	195

1 *The Company acquired the right to apply for a $54 million (US$55 million) United States Treasury grant under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property. The grant, which was applied for subsequent to commercial operations, was received in October 2012.*

OTHER ACQUISITIONS

In December 2014, the Company acquired an incremental 30% interest in the Massif du Sud Wind Project (Massif du Sud) for cash consideration of $102 million, bringing its total interest in the wind project to 80%. The Company acquired its original 50% interest in Massif du Sud in December 2012. The Company's interest in Massif du Sud represents an undivided interest, with $97 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Massif du Sud is currently operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

In October 2014, the Company acquired an incremental 17.5% interest in the Lac Alfred Wind Project (Lac Alfred) for cash consideration of $121 million, bringing its total interest in the wind project to 67.5%. The Company acquired its original 50% interest in Lac Alfred in December 2011. The Company's interest in Lac Alfred represents an undivided interest, with $115 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Lac Alfred is currently operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

In July 2013, the Company acquired a 50% undivided interest in the Saint Robert Bellarmin Wind Project (Saint Robert), located in Quebec for a purchase price of $106 million, of which $100 million was allocated to Property, plant and equipment, with the remainder allocated to Intangible assets. Saint Robert is operational and is presented within the Gas Pipelines, Processing and Energy Services segment.

OTHER DISPOSITIONS

In November 2014, the Company sold one of its non-core assets within Enbridge Offshore Pipelines (Offshore), which include pipeline facilities located in Louisiana, to a third party for $7 million (US$7 million). A gain of $22 million (US$19 million) was presented within Other income/(expense) on the Consolidated Statements of Earnings.

In July 2014, the Company sold a 35% equity interest in the Southern Access Extension Project, a pipeline project under construction, to an unrelated party for gross proceeds of $73 million (US$68 million). As the fair value of the consideration received equalled the carrying value of the asset sold, no gain or loss was recognized on the sale *(Note 11)*.

In March 2014, the Company sold an Alternative and Emerging Technologies investment within the Corporate segment to a third party for $19 million. A gain of $16 million was presented within Other income/(expense) on the Consolidated Statements of Earnings.

In November 2013, EEP sold one of its non-core liquids assets, a storage facility in Kansas, to a third party for $41 million (US$40 million). A gain of $18 million (US$17 million) was presented within Other income/(expense) on the Consolidated Statements of Earnings.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Unbilled revenues	**2,218**	2,773
Trade receivables	**1,168**	1,154
Taxes receivable	**522**	200
Regulatory assets	**567**	54
Short-term portion of derivative assets *(Note 23)*	**568**	385
Prepaid expenses and deposits	**103**	123
Current deferred income taxes *(Note 24)*	**245**	120
Dividends receivable	**26**	26
Other	**129**	159
Allowance for doubtful accounts	**(42)**	(38)
	5,504	4,956

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain of EEP's 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$378 million ($439 million) and US$380 million ($404 million) as at December 31, 2014 and December 31, 2013, respectively.

8. INVENTORY

December 31,	**2014**	2013
(millions of Canadian dollars)		
Natural gas	**678**	527
Other commodities	**470**	588
	1,148	1,115

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $174 million for the year ended December 31, 2014 (2013 - $4 million; 2012 - $10 million) to reduce the cost basis of inventory to market value.

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2014**	2013
(millions of Canadian dollars)			
Liquids Pipelines[1]			
Pipeline	2.6%	**12,515**	8,974
Pumping equipment, buildings, tanks and other	3.0%	**7,715**	6,248
Land and right-of-way	1.4%	**520**	253
Under construction	-	**5,578**	4,846
		26,328	20,321
Accumulated depreciation		**(4,312)**	(3,838)
		22,016	16,483
Gas Distribution			
Gas mains, services and other	3.1%	**8,427**	8,020
Land and right-of-way	1.2%	**84**	79
Under construction	-	**352**	179
		8,863	8,278
Accumulated depreciation		**(2,256)**	(2,074)
		6,607	6,204
Gas Pipelines, Processing and Energy Services			
Pipeline	4.2%	**633**	456
Wind turbines, solar panels and other	4.0%	**2,371**	1,092
Power transmission	2.1%	**397**	384
Canadian Midstream gas gathering and processing	2.9%	**778**	557
Land and right-of-way	1.1%	**28**	6
Under construction	-	**1,172**	1,233
		5,379	3,728
Accumulated depreciation		**(454)**	(344)
		4,925	3,384
Sponsored Investments			
Pipeline	3.0%	**11,564**	8,979
Pumping equipment, buildings, tanks and other	3.0%	**7,806**	6,076
Wind turbines, solar panels and other	4.0%	**1,549**	1,548
Land and right-of-way	2.2%	**1,040**	755
Under construction	-	**2,126**	2,201
		24,085	19,559
Accumulated depreciation		**(3,903)**	(3,429)
		20,182	16,130
Corporate			
Other	12.8%	**80**	84
Under construction	-	**69**	36
		149	120
Accumulated depreciation		**(49)**	(42)
		100	78
		53,830	42,279

1 *In July 2014, $62 million of Property, plant and equipment was disposed as part of the sale of 35% equity interest in the Southern Access Extension Project. The remaining balance of $136 million in Property, plant and equipment was reclassified to Long-term investments (Note 11).*

Depreciation expense for the year ended December 31, 2014 was $1,461 million (2013 - $1,282 million; 2012 - $1,174 million).

GAS PIPELINES, PROCESSING AND ENERGY SERVICES
Impairment
In December 2012, the Company recorded 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 in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas of the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

The impairment charge was based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and was presented within Operating and administrative expense on the Consolidated Statements of Earnings. The charge was inclusive of $50 million related to abandonment costs which were reasonably determined given the expected timing and scope of certain asset retirements. A portion of the impairment charge was subsequently reclassified to discontinued operations as discussed below.

Discontinued Operations
In March 2014, the Company completed the sale of certain of its Offshore 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 (2013 - $26 million; 2012 - $32 million) and related cash flows, have also been presented as discontinued operations for the year ended December 31, 2014. At December 31, 2013, the related assets and liabilities were classified as held for sale and were measured at the lower of their carrying amount and estimated fair value less cost to sell which did not result in a fair value adjustment. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

10. VARIABLE INTEREST ENTITIES

The Company is required to consolidate variable interest entities in which the Company is the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company assesses all aspects of its interest in the entity and uses its judgment when determining if the Company is the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE’s capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reassessment of the primary beneficiary conclusion is conducted when there are changes in the facts and circumstances related to a VIE.

SPONSORED INVESTMENTS
Enbridge Income Fund
The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 66.4% (2013 - 67.3%; 2012 - 67.7%) economic interest, held indirectly through a common investment in ENF, a direct common trust unit investment in the Fund and a preferred unit investment in a wholly-owned subsidiary of the Fund. Enbridge also serves in the capacity of Manager of ENF, the Fund and its subsidiaries. The creditors of the Fund have no recourse to the general credit of the Company.

The summarized impact of the Company’s interest in the Fund on earnings, cash flows and financial position is presented below. Earnings include the results of operations of certain assets and equity interests acquired by the Fund from indirect wholly-owned subsidiaries of Enbridge since their acquisition in December 2012 and November 2014 *(Note 19)*.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Revenues	**416**	403	288
Operating and administrative expense	**(135)**	(126)	(83)
Depreciation and amortization	**(136)**	(130)	(87)
Income from equity investments	**72**	57	54
Interest expense	**(59)**	(91)	(68)
Income taxes	**(43)**	(27)	(35)
Earnings	**115**	86	69
Loss attributable to noncontrolling interests	**11**	24	12
Earnings attributable to Enbridge Inc.	**126**	110	81
Cash flows			
Cash provided by operating activities	**277**	260	200
Cash used in investing activities	**(1,806)**	(98)	(160)
Cash provided by/(used in) financing activities	**1,531**	(323)	1,495
Increase/(decrease) in cash and cash equivalents	**2**	(161)	1,535

December 31,	**2014**	2013
(millions of Canadian dollars)		
Current assets	**114**	84
Property, plant and equipment, net	**2,226**	2,317
Long-term investments	**441**	227
Deferred amounts and other assets[1]	**1,304**	130
Current liabilities	**(149)**	(388)
Long-term debt	**(2,544)**	(1,364)
Other long-term liabilities	**(79)**	(26)
Deferred income taxes	**(441)**	(426)
Net assets before noncontrolling interests	**872**	554

1 *Includes an investment of $945 million in Class A units of Enbridge subsidiaries by the Fund completed in November 2014.*

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Magicat Holdco LLC

Through its 80% controlling interest in Magicat Holdco LLC acquired on December 31, 2014, the Company is the primary beneficiary of the Magic Valley and Wildcat wind farms *(Note 6)*. These wind farms are considered VIEs by virtue of the Company's voting rights and its power to direct the activities that most significantly impact the economic performance of the wind farms.

As at December 31, 2014, the Company's investment in the Magic Valley and Wildcat wind farms was $394 million, with their carrying amounts of assets and liabilities consolidated by the Company of $759 million and $14 million, respectively. The wind farms' assets can only be used to settle their obligations. Enbridge does not have an obligation to provide financial support to these VIEs other than an indirect obligation, as prescribed by the terms of certain indemnities and guarantees, to pay the liabilities of the wind farms in the event of a default.

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2014**	2013
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Seaway Pipeline	50.0%	**2,782**	2,048
Chicap Pipeline	43.8%	**33**	29
Mustang Pipeline	30.0%	**25**	23
Southern Access Extension	65.0%	**263**	-
Other	75.0%	**7**	-
Gas Pipelines, Processing and Energy Services			
Aux Sable	42.7% - 50.0%	**311**	306
Alliance Pipeline US[1]	-	**-**	201
Vector Pipeline	60.0%	**141**	125
Offshore - various joint ventures	22.0% - 74.3%	**429**	401
Other	33.3% - 70.0%	**12**	11
Sponsored Investments			
Texas Express Pipeline	35.0%	**442**	396
Alliance Pipeline Canada and US[1]	50.0%	**374**	165
Other	50.0%	**67**	62
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	**-**	-
Other	19.3% - 49.99%	**45**	56
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		**323**	287
Other		**154**	102
		5,408	4,212

1 In November 2014, Enbridge's interest in Alliance Pipeline US was transferred to the Fund. As a result, $203 million of Long-term investments as at December 31, 2014 were reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The Alliance Pipeline US balance of $201 million in Gas Pipelines, Processing and Energy Services as at December 31, 2013 has not been reclassified for presentation purposes.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date, which is comprised of $742 million (2013 - $680 million) in Goodwill and $494 million (2013 - $517 million) in amortizable assets.

JOINT VENTURES

Summarized combined financial information of the Company's interest in unconsolidated equity investments in joint ventures is as follows:

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Revenues	**1,790**	1,212	956
Commodity costs	**(661)**	(371)	(236)
Operating and administrative expense	**(360)**	(268)	(244)
Depreciation and amortization	**(232)**	(175)	(159)
Other income/(expense)	**(1)**	4	4
Interest expense	**(84)**	(74)	(81)
Earnings before income taxes	**452**	328	240

December 31,	**2014**	2013
(millions of Canadian dollars)		
Current assets	**472**	366
Property, plant and equipment, net	**5,169**	4,050
Deferred amounts and other assets	**34**	35
Intangible assets, net	**77**	75
Goodwill	**742**	680
Current liabilities	**(712)**	(395)
Long-term debt	**(811)**	(994)
Other long-term liabilities	**(85)**	(50)
Net assets	**4,886**	3,767

Alliance Pipeline System

Certain assets of the Alliance Pipeline System (Alliance System) are pledged as collateral to Alliance System lenders.

Southern Access Extension Project

On July 1, 2014, under an agreement with an unrelated third party, the Company sold a 35% equity interest in the Southern Access Extension Project (the Project). Prior to this sale, the subsidiary executing the Project was wholly-owned and consolidated within the Liquids Pipelines segment. The Company concluded that under the agreement, the purchaser of the 35% equity interest is entitled to substantive participating rights; however, the Company continues to exercise significant influence. As a result, effective July 1, 2014, the Company discontinued consolidation of the Project and recognized its remaining 65% equity interest as a long-term equity investment within the Liquids Pipelines segment.

OTHER EQUITY INVESTMENTS

Noverco

As at December 31, 2014, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2013 - 38.9%; 2012 - 38.9%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

As at December 31, 2014, Noverco owned an approximate 3.6% (2013 - 3.9%; 2012 - 6.0%) reciprocal shareholding in common shares of Enbridge. The change in reciprocal shareholding compared with prior years reflected the sale of Enbridge common shares by Noverco. Through secondary offerings, Noverco sold 22.5 million Enbridge common shares in 2012, 15 million common shares in 2013 and a further 1.3 million common shares in 2014. The transactions were recognized as issuances of treasury stock on the Consolidated Statements of Changes in Equity. In relation to the 2012 and 2013 transactions, Enbridge's share of the net after-tax proceeds of $297 million and $248 million were received as dividends from Noverco in May 2012 and June 2013, respectively, and reflected in Operating activities on the Consolidated Statements of Cash Flows.

As a result of Noverco's reciprocal shareholding in Enbridge common shares, the Company has an indirect pro-rata interest of 1.4% (2013 - 1.5%; 2012 - 2.1%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $83 million at December 31, 2014 (2013 - $86 million; 2012 - $126 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco.

12. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets	**1,752**	1,172
Long-term portion of derivative assets *(Note 23)*	**199**	413
Affiliate long-term note receivable *(Note 28)*	**183**	185
Contractual receivables	**382**	356
Deferred financing costs	**166**	135
Other	**526**	401
	3,208	2,662

As at December 31, 2014, deferred amounts of $366 million (2013 - $307 million) were subject to amortization and are presented net of accumulated amortization of $189 million (2013 - $159 million). Amortization expense for the year ended December 31, 2014 was $38 million (2013 - $34 million; 2012 - $25 million).

13. INTANGIBLE ASSETS

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.9%	**1,049**	**337**	**712**
Natural gas supply opportunities	3.7%	**340**	**83**	**257**
Power purchase agreements	3.8%	**96**	**10**	**86**
Transportation agreements	3.7%	**56**	**18**	**38**
Other	3.6%	**85**	**12**	**73**
		1,626	**460**	**1,166**

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.2%	825	241	584
Natural gas supply opportunities	3.7%	311	65	246
Power purchase agreements	4.0%	87	7	80
Transportation agreements	3.7%	53	15	38
Other	4.0%	64	8	56
		1,340	336	1,004

Total amortization expense for intangible assets was $106 million (2013 - $82 million; 2012 - $64 million) for the year ended December 31, 2014. The Company expects amortization expense for intangible assets for the years ending December 31, 2015 through 2019 of $109 million, $96 million, $85 million, $76 million and $67 million, respectively.

14. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2013	22	-	13	384	-	419
Foreign exchange and other	1	-	1	24	-	26
Balance at December 31, 2013	23	-	14	408	-	445
Foreign exchange and other	**3**	**-**	**1**	**34**	**-**	**38**
Balance at December 31, 2014	**26**	**-**	**15**	**442**	**-**	**483**

The Company did not recognize any goodwill impairments for the years ended December 31, 2014 and 2013.

15. ACCOUNTS PAYABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Operating accrued liabilities	**2,939**	3,577
Trade payables	**414**	300
Construction payables	**746**	1,188
Current derivative liabilities *(Note 23)*	**1,020**	837
Contractor holdbacks	**368**	211
Taxes payable	**555**	176
Security deposits	**63**	65
Asset retirement obligations *(Note 18)*	**53**	-
Other	**286**	310
	6,444	6,664

16. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2014**	2013
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.2%	2024	**200**	200
Medium-term notes[1]	4.8%	2015-2043	**2,986**	2,985
Southern Lights project financing[2,3]	4.0%	2040	**1,571**	1,480
Commercial paper and credit facility draws			**163**	266
Other[4]			**9**	11
Gas Distribution				
Debentures	9.9%	2024	**85**	85
Medium-term notes	4.7%	2016-2050	**3,033**	2,702
Commercial paper and credit facility draws			**939**	374
Sponsored Investments				
Junior subordinated notes[5]	8.1%	2067	**464**	425
Medium-term notes	3.9%	2016-2044	**2,405**	1,615
Senior notes[6]	6.1%	2016-2040	**4,815**	4,201
Commercial paper and credit facility draws[7]			**2,614**	717
Corporate				
United States dollar term notes[8]	3.5%	2015-2044	**3,886**	2,393
Medium-term notes	4.3%	2015-2064	**6,048**	4,518
Commercial paper and credit facility draws[9]			**6,182**	3,598
Gas Pipelines, Processing and Energy Services				
Promissory Note[10]		2015	**103**	-
Other[11]			**(35)**	(28)
Total debt			**35,468**	25,542
Current maturities			**(1,004)**	(2,811)
Short-term borrowings[12]			**(1,041)**	(374)
Long-term debt			**33,423**	22,357

1 *Included in medium-term notes is $100 million with a maturity date of 2112.*
2 *2014 - $348 million and US$1,054 million (2013 - $352 million and US$1,061 million).*
3 *On August 18, 2014, long-term private debt was issued with the proceeds utilized to repay the construction credit facilities on a dollar-for-dollar basis.*
4 *Primarily capital lease obligations.*
5 *2014 - US$400 million (2013 - US$400 million).*
6 *2014 - US$4,150 million (2013 - US$3,950 million).*
7 *2014 - $140 million and US$2,132 million (2013 - $41 million and US$635 million).*
8 *2014 - US$3,350 million (2013 - US$2,250 million).*
9 *2014 - $3,217 million and US$2,555 million (2013 - $2,476 million and US$1,055 million).*
10 *A non-interest bearing demand promissory note that was subsequently paid on January 9, 2015.*
11 *Primarily debt discount.*
12 *Weighted average interest rate - 1.4% (2013 - 1.1%).*

For the years ending December 31, 2015 through 2019, debenture and term note maturities are $1,001 million, $1,834 million, $2,429 million, $1,075 million, $1,742 million, respectively, and $17,411 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2015 through 2019 are $1,432 million, $1,404 million, $1,312 million, $1,170 million and $991 million, respectively. At December 31, 2014, all debt is unsecured and at December 31, 2013, all debt is unsecured except for the Southern Lights project financing which was collateralized by the Southern Lights project assets of approximately $2,680 million.

INTEREST EXPENSE

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Debentures and term notes	**1,425**	1,123	986
Commercial paper and credit facility draws	**71**	34	33
Southern Lights project financing	**49**	40	38
Capitalized	**(416)**	(250)	(216)
	1,129	947	841

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

		December 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**163**	**137**	300
Gas Distribution	2016-2019	**1,008**	**943**	**65**	707
Sponsored Investments	2016-2019	**4,531**	**2,745**	**1,786**	4,781
Corporate	2016-2019	**12,772**	**6,223**	**6,549**	11,775
Total committed credit facilities[2]		**18,611**	**10,074**	**8,537**	17,563

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 related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis. Excluded from December 31, 2014 total facilities above was Southern Lights project financing facilities of $28 million (2013 - $1,570 million). Included in the 2013 facilities for Southern Lights were $63 million for debt service reserve letters of credit.*

In addition to the committed credit facilities noted above, the Company also has $361 million (2013 - $35 million) of uncommitted demand credit facilities, of which $80 million (2013 - $17 million) was unutilized as at December 31, 2014.

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 2016 to 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $8,960 million (2013 - $4,580 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2014, the Company was in compliance with all debt covenants.

17. OTHER LONG-TERM LIABILITIES

December 31,	2014	2013
(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 5)*	**757**	929
Derivative liabilities *(Note 23)*	**2,078**	1,395
Pension and OPEB liabilities *(Note 25)*	**584**	264
Asset retirement obligations *(Note 18)*	**132**	24
Environmental liabilities	**70**	28
Other	**420**	298
	4,041	2,938

18. ASSET RETIREMENT OBLIGATIONS

Included in ARO at December 31, 2014 was an amount of $21 million (2013 - $20 million) for the retirement of certain assets of the Fund which is estimated to be settled between 2016 and 2060. During the year ended December 31, 2014, the Company recognized ARO in the amount of $177 million. Of the amount, $74 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System and $103 million related to the Canadian and United States portions of the Line 3 Replacement

Program targeted to be completed in 2017 whereby the Company will replace the existing Line 3 pipeline in Canada and the United States.

The liability for the expected cash flows as recognized in the financial statements reflected discount rates ranging from 4.6% to 8.1% (2013 - 8.1%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Obligations, beginning of year	**24**	23
Liabilities incurred	**177**	-
Liabilities settled	**(24)**	-
Foreign currency translation adjustment	**5**	-
Accretion expense	**3**	1
Obligations, end of year	**185**	24
Presented as follows:		
Accounts payable and other *(Note 15)*	**53**	-
Other long-term liabilities *(Note 17)*	**132**	24
	185	24

19. NONCONTROLLING INTERESTS

December 31,	**2014**	2013
(millions of Canadian dollars)		
EEP	**748**	2,810
Enbridge Energy Management, L.L.C. (EEM)	**790**	1,079
Renewable energy assets *(Note 6)*	**351**	-
EGD preferred shares	**100**	100
Other	**26**	25
	2,015	4,014

Noncontrolling interests in EEP represented the 79.5% (2013 - 79.4%) interest in EEP held by public unitholders, as well as interests of third parties in subsidiaries of EEP, including Midcoast Energy Partners, L.P. (MEP). The decrease in noncontrolling interests in EEP reflected the EEP 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 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 $1,601 million and $762 million, respectively.

During the year ended December 31, 2014, EEP distributed $504 million (2013 - $463 million; 2012 - $419 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

In May 2013, EEP formed MEP as its wholly-owned subsidiary. Subsequently, on November 13, 2013, MEP completed its initial public offering of 18.5 million Class A common units representing limited partner interests and subsequently issued an additional 2.8 million Class A common units pursuant to an underwriters' over-allotment option. MEP received proceeds of approximately $372 million (US$355 million). Upon finalization of the offering, MEP's initial assets consisted of an approximate 39% ownership interest in EEP's natural gas and NGL midstream business. EEP retained a 2% GP interest, an approximate 52% limited partner interest and all incentive distribution rights (IDR) in MEP, in addition to its 61% direct interest in the natural gas and NGL midstream assets.

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 $376 million (US$350 million). Upon finalization of this transaction, EEP continued to retain a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP. However, EEP's direct interest in entities or partnerships holding the natural gas and NGL midstream operations reduced from 61% to 48%, with the remaining ownership held by MEP.

Noncontrolling interests in Enbridge Energy Management, LLC (EEM) represented the 88.3% (2013 - 88.3%) of the listed shares of EEM not held by the Company. The decrease in the carrying value of the Noncontrolling interests in EEM is due to the fair value allocation attributable to EEM as a result of the EEP equity restructuring as discussed above. In 2013, EEM completed a listed share issuance in which the Company did not participate and which resulted in contributions of $523 million from noncontrolling interest holders.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2014, no preferred shares have been redeemed.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Balance at beginning of year	**1,053**	1,000	640
Loss	**(11)**	(24)	(12)
Other comprehensive income/(loss)			
Change in unrealized gains/(loss) on cash flow hedges, net of tax	**(15)**	4	(1)
Change in foreign currency translation adjustment	**5**	-	-
Other comprehensive income/(loss)	**(10)**	4	(1)
Distributions to unitholders	**(79)**	(72)	(49)
Contributions from unitholders	**323**	92	225
Redemption value adjustment	**973**	53	197
Balance at end of year	**2,249**	1,053	1,000

Redeemable noncontrolling interests in the Fund at December 31, 2014 represented 70.6% (2013 - 68.6%; 2012 - 67.7%) of interests in the Fund's trust units that are held by third parties. In November 2014, the Fund acquired Enbridge's 50% interest in Alliance Pipeline US and subscribed for and purchased Class A units of Enbridge's subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline for a total consideration of approximately $1.8 billion, including $421 million in cash, $878 million in the form of a long-term note payable by the Fund, bearing interest of 5.5% per annum and was fully repaid at December 31, 2014, and $461 million in the form of preferred units of Enbridge Commercial Trust, a subsidiary of the Fund. To fund the cash component of the consideration, the Fund issued approximately $421 million of trust units to ENF. To purchase the trust units from the Fund, ENF completed a bought deal public offering of common shares for approximately $337 million and issued additional common shares to Enbridge for approximately $84 million in order for Enbridge to maintain its 19.9% interest in ENF. As a result of the transfer, redeemable noncontrolling interests in the Fund increased from 68.6% to 70.6% and contributions of $323 million, net of share issue costs, were received from redeemable noncontrolling interest holders.

During the year ended December 31, 2013, the Fund completed a unit issuance in which the Company did not participate, resulting in an increase in the redeemable noncontrolling interests from 67.7% to 68.6%. This resulted in contributions of $92 million from redeemable noncontrolling interest holders.

In December 2012, the Fund acquired Greenwich Wind Energy Project, Amherstburg Solar Project, Tilbury Solar Project, Hardisty Caverns and Hardisty Contract Terminals from Enbridge and wholly-owned subsidiaries of Enbridge for proceeds of $1.2 billion. Trust units were issued by the Fund to partially finance this acquisition, resulting in an increase in interests held by third parties in 2012 and contributions from noncontrolling unitholders of $225 million.

Distributions to noncontrolling unitholders were made on a monthly basis for the years ended December 31, 2014, 2013 and 2012 in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2014		2013		2012	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**831**	**5,744**	805	4,732	781	3,969
Common Shares issued[1]	**9**	**446**	13	582	10	388
Dividend Reinvestment and Share Purchase Plan (DRIP)	**9**	**428**	8	361	8	297
Shares issued on exercise of stock options	**3**	**51**	5	69	6	78
Balance at end of year	**852**	**6,669**	831	5,744	805	4,732

1 Gross proceeds - $460 million (2013 - $600 million; 2012 - $400 million); net issuance costs - $14 million (2013 - $18 million; 2012 - $12 million).

PREFERENCE SHARES

December 31,	2014 Number of Shares	2014 Amount	2013 Number of Shares	2013 Amount	2012 Number of Shares	2012 Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J	**8**	**199**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	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)		(78)
Balance at end of period		**6,515**		5,141		3,707

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	4.4%	$1.100	$25	June 1, 2020	Series 14
Preference Shares, Series 15	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 a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

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)).

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2013 - 15 million; 2012 - 20 million) resulting from the Company's reciprocal investment in Noverco.

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

December 31,	**2014**	2013	2012
(number of common shares in millions)			
Weighted average shares outstanding	**829**	806	772
Effect of dilutive options	**11**	11	13
Diluted weighted average shares outstanding	**840**	817	785

For the year ended December 31, 2014, 6,058,580 anti-dilutive stock options (2013 - 6,327,500; 2012 - 5,733,000) with a weighted average exercise price of $48.78 (2013 - $44.85; 2012 - $38.32) were excluded from the diluted earnings per common share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 49 million have been issued to date. A further 71 million common shares have been reserved for issuance for the 2007 ISO and PBSO plans, of which eight million have been exercised and issued from treasury to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISO to purchase common shares at the market price on the grant date. ISO vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**29,602**	**30.52**		
Options granted	**5,963**	**48.80**		
Options exercised[1]	**(3,973)**	**22.20**		
Options cancelled or expired	**(262)**	**41.33**		
Options outstanding at end of year	**31,330**	**34.97**	**6.6**	**523**
Options vested at end of year[2]	**16,591**	**27.25**	**5.2**	**405**

1 *The total intrinsic value of ISO exercised during the year ended December 31, 2014 was $117 million (2013 - $98 million; 2012 - $130 million) and cash received on exercise was $37 million (2013 - $24 million; 2012 - $69 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2014 was $26 million (2013 - $22 million; 2012 - $19 million).*

Weighted average assumptions used to determine the fair value of ISO granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2014**	2013	2012
Fair value per option *(Canadian dollars)*[1]	**5.53**	5.27	4.81
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**16.9%**	17.4%	19.7%
Expected dividend yield[4]	**2.9%**	2.8%	3.0%
Risk-free interest rate[5]	**1.6%**	1.2%	1.3%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.45 (2013 - $5.15; 2012 - $4.65) for Canadian employees and US$5.35 (2013 - US$5.63; 2012 - US$5.58) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2014 for ISO was $29 million (2013 - $27 million; 2012 - $23 million). At December 31, 2014, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $42 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE BASED STOCK OPTIONS

PBSO are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSO were granted on August 15, 2007, February 19, 2008, August 15, 2012 and March 13, 2014 under the 2007 plan. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements were fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. Currently, two of the three performance targets have been met as at December 31, 2014 and the options are exercisable until August 15, 2020. Time vesting requirements for the 2014 grant will be fulfilled evenly over a four-year term, ending March 13, 2018. The 2014 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. Currently, one of the two performance targets have been met as at December 31, 2014 and the options are exercisable until August 15, 2020.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**4,373**	**35.56**		
Options granted	**138**	**48.81**		
Options exercised[1]	**-**	**-**		
Options outstanding at end of year	**4,511**	**35.97**	**4.5**	**71**
Options vested at end of year[2]	**1,964**	**30.93**	**3.4**	**41**

1 No PBSO were exercised in 2014. The total intrinsic value of PBSO exercised during the year ended December 31, 2013 and 2012 was $62 million and $20 million, respectively, and cash received on exercise was $28 million and $12 million.

2 The total fair value of options vested under the PBSO Plan during the year ended December 31, 2014 was $5 million (2013 - nil; 2012 - $1 million).

Assumptions used to determine the fair value of PBSO granted using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2014	2012
Fair value per option *(Canadian dollars)*	**5.77**	4.25
Valuation assumptions		
Expected option term *(years)*[1]	**6.5**	8
Expected volatility[2]	**15.0%**	16.1 %
Expected dividend yield[3]	**2.8%**	2.8%
Risk-free interest rate[4]	**1.7%**	1.6%

1 The expected option term is based on historical exercise practice.

2 Expected volatility is determined with reference to historic daily share price volatility.

3 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

4 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.

Compensation expense recorded for the year ended December 31, 2014 for PBSO was $3 million (2013 - $3 million; 2012 - $2 million). At December 31, 2014, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $9 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two if the Company performs within the highest range of its performance targets. The 2012, 2013 and 2014 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2014 expense, multipliers of two, based upon multiplier estimates at December 31, 2014, were used for each of the 2012, 2013 and 2014 PSU grants.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**591**		
Units granted	**274**		
Units cancelled	**(2)**		
Units matured[1]	**(332)**		
Dividend reinvestment	**24**		
Units outstanding at end of year	**555**	**1.5**	**66**

1 The total amount paid during the year ended December 31, 2014 for PSU was $36 million (2013 - $48 million; 2012 - $25 million).

Compensation expense recorded for the year ended December 31, 2014 for PSU was $40 million (2013 - $25 million; 2012 - $49 million). As at December 31, 2014, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $34 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**1,828**		
Units granted	**1,019**		
Units cancelled	**(99)**		
Units matured[1]	**(867)**		
Dividend reinvestment	**78**		
Units outstanding at end of year	**1,959**	**1.5**	**116**

1 The total amount paid during the year ended December 31, 2014 for RSU was $45 million (2013 - $41 million; 2012 - $37 million).

Compensation expense recorded for the year ended December 31, 2014 for RSU was $44 million (2013 - $36 million; 2012 - $32 million). As at December 31, 2014, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $58 million and is expected to be fully recognized over a weighted average period of approximately two years.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2014, 2013 and 2012, 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	**(857)**	**(301)**	**1,087**	**10**	**(265)**	**(326)**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**201**	**-**	**-**	**-**	**-**	**201**
Commodity contracts[2]	**(2)**	**-**	**-**	**-**	**-**	**(2)**
Foreign exchange contracts[3]	**8**	**-**	**-**	**-**	**-**	**8**
Other contracts[4]	**(23)**	**-**	**-**	**-**	**-**	**(23)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**-**	**-**	**-**	**-**	**18**	**18**
	(673)	**(301)**	**1,087**	**10**	**(247)**	**(124)**
Tax impact						
Income tax on amounts retained in AOCI	**231**	**31**	**-**	**-**	**74**	**336**
Income tax on amounts reclassified to earnings	**(45)**	**-**	**-**	**-**	**(3)**	**(48)**
	186	**31**	**-**	**-**	**71**	**288**
Balance at December 31, 2014	**(488)**	**108**	**309**	**(5)**	**(359)**	**(435)**

	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	707	(111)	487	11	165	1,259
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	134	-	-	-	-	134
Commodity contracts[2]	(1)	-	-	-	-	(1)
Foreign exchange contracts[3]	(8)	-	-	-	-	(8)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	36	36
	832	(111)	487	11	201	1,420
Tax impact						
Income tax on amounts retained in AOCI	(176)	15	-	-	(51)	(212)
Income tax on amounts reclassified to earnings	(36)	-	-	-	(9)	(45)
	(212)	15	-	-	(60)	(257)
Balance at December 31, 2013	(1)	378	(778)	(15)	(183)	(599)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
Balance at January 1, 2012	(476)	461	(1,167)	(28)	(286)	(1,496)
Other comprehensive income/(loss) retained in AOCI	(172)	16	(98)	7	(75)	(322)
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	(17)	-	-	-	-	(17)
Commodity contracts[2]	(4)	-	-	-	-	(4)
Foreign exchange contracts[3]	1	-	-	-	-	1
Other contracts[4]	2	-	-	-	-	2
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	23	23
	(190)	16	(98)	7	(52)	(317)
Tax impact						
Income tax on amounts retained in AOCI	36	(3)	-	(5)	19	47
Income tax on amounts reclassified to earnings	9	-	-	-	(5)	4
	45	(3)	-	(5)	14	51
Balance at December 31, 2012	(621)	474	(1,265)	(26)	(324)	(1,762)

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.*

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and 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 via 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 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 4.1%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt 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, RSU. 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 December 31, 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 amount in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 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 *(Note 7)*						
Foreign exchange contracts	**3**	**7**	**3**	**13**	**(13)**	**-**
Interest rate contracts	**8**	**-**	**-**	**8**	**(7)**	**1**
Commodity contracts	**34**	**-**	**501**	**535**	**(130)**	**405**
Other contracts	**4**	**-**	**8**	**12**	**-**	**12**
	49	**7**	**512**	**568**	**(150)**	**418**
Deferred amounts and other assets *(Note 12)*						
Foreign exchange contracts	**33**	**18**	**-**	**51**	**(51)**	**-**
Interest rate contracts	**5**	**-**	**-**	**5**	**(5)**	**-**
Commodity contracts	**17**	**-**	**118**	**135**	**(43)**	**92**
Other contracts	**5**	**-**	**3**	**8**	**-**	**8**
	60	**18**	**121**	**199**	**(99)**	**100**
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	**(3)**	**(80)**	**(218)**	**(301)**	**13**	**(288)**
Interest rate contracts	**(438)**	**-**	**-**	**(438)**	**7**	**(431)**
Commodity contracts	**-**	**-**	**(281)**	**(281)**	**97**	**(184)**
	(441)	**(80)**	**(499)**	**(1,020)**	**117**	**(903)**
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	**-**	**(49)**	**(1,147)**	**(1,196)**	**51**	**(1,145)**
Interest rate contracts	**(576)**	**-**	**-**	**(576)**	**5**	**(571)**
Commodity contracts	**-**	**-**	**(306)**	**(306)**	**43**	**(263)**
	(576)	**(49)**	**(1,453)**	**(2,078)**	**99**	**(1,979)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**33**	**(104)**	**(1,362)**	**(1,433)**	**-**	**(1,433)**
Interest rate contracts	**(1,001)**	**-**	**-**	**(1,001)**	**-**	**(1,001)**
Commodity contracts	**51**	**-**	**32**	**83**	**(33)**[1]	**50**
Other contracts	**9**	**-**	**11**	**20**	**-**	**20**
	(908)	**(104)**	**(1,319)**	**(2,331)**	**(33)**	**(2,364)**

1 Amount available for offset includes $33 million of cash collateral.

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[1]	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
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 *(Note 12)*						
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 *(Note 15)*						
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 *(Note 17)*						
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.

December 31, 2014	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**240**	**25**	**413**	**2**	**2**	**2**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**3,203**	**2,470**	**2,832**	**3,100**	**2,441**	**2,901**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**15**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**5,767**	**5,486**	**4,851**	**3,529**	**222**	**469**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**3,528**	**1,762**	**2,470**	**1,176**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**41**	**51**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(62)**	**(10)**	**(25)**	**(1)**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**3**	**(18)**	**(18)**	**(9)**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(5)**	**-**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**25**	**40**	**40**	**30**	**31**	**-**

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.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**8**	56	(12)
Interest rate contracts	**(1,086)**	814	(46)
Commodity contracts	**50**	(9)	52
Other contracts	**13**	(2)	(3)
Net investment hedges			
Foreign exchange contracts	**(113)**	(81)	1
	(1,128)	778	(8)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	**8**	(8)	1
Interest rate contracts[2]	**101**	107	(1)
Commodity contracts[3]	**4**	1	(3)
Other contracts[4]	**(7)**	-	2
	106	100	(1)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**216**	51	23
Commodity contracts[3]	**(6)**	(3)	(3)
	210	48	20

1 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
2 *Reported as an increase/(decrease) within 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 $64 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 49 months as at December 31, 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.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(936)**	(738)	120
Interest rate contracts[2]	**4**	(10)	(2)
Commodity contracts[3]	**1,031**	(496)	(765)
Other contracts[4]	**7**	(3)	(2)
Total unrealized derivative fair value gains/(loss)	**106**	(1,247)	(649)

1 *Reported within Transportation and other services revenues (2014 - $496 million loss; 2013 - $352 million loss; 2012 - $150 million gain) and Other income/(expense) (2014 - $440 million loss; 2013 - $386 million loss; 2012 - $30 million loss) in the Consolidated Statements of Earnings.*

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

3 *Reported within Transportation and other services revenues (2014 - $741 million gain; 2013 - $375 million loss; 2012 - $681 million loss), Commodity costs (2014 - $303 million gain; 2013 - $35 million loss; 2012 - $21 million loss) and Operating and administrative expense (2014 - $13 million loss; 2013 - $86 million loss; 2012 - $63 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 December 31, 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. In order to mitigate this risk, the Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, 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:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Canadian financial institutions	**58**	230
United States financial institutions	**240**	227
European financial institutions	**73**	192
Other[1]	**310**	97
	681	746

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

As at December 31, 2014, the Company had provided letters of credit totalling $382 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The

Company held $33 million of cash collateral on derivative asset exposures at December 31, 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.

Fair Value of Derivatives

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

December 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**13**	**-**	**13**
Interest rate contracts	**-**	**8**	**-**	**8**
Commodity contracts	**62**	**140**	**333**	**535**
Other contracts	**-**	**12**	**-**	**12**
	62	**173**	**333**	**568**
Long-term derivative assets				
Foreign exchange contracts	**-**	**51**	**-**	**51**
Interest rate contracts	**-**	**5**	**-**	**5**
Commodity contracts	**-**	**22**	**113**	**135**
Other contracts	**-**	**8**	**-**	**8**
	-	**86**	**113**	**199**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(301)**	**-**	**(301)**
Interest rate contracts	**-**	**(438)**	**-**	**(438)**
Commodity contracts	**(28)**	**(137)**	**(116)**	**(281)**
	(28)	**(876)**	**(116)**	**(1,020)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(1,196)**	**-**	**(1,196)**
Interest rate contracts	**-**	**(576)**	**-**	**(576)**
Commodity contracts	**-**	**(125)**	**(181)**	**(306)**
	-	**(1,897)**	**(181)**	**(2,078)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(1,433)**	**-**	**(1,433)**
Interest rate contracts	**-**	**(1,001)**	**-**	**(1,001)**
Commodity contracts	**34**	**(100)**	**149**	**83**
Other contracts	**-**	**20**	**-**	**20**
	34	**(2,514)**	**149**	**(2,331)**

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:

December 31, 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	(7)	Forward gas price	2.95	4.31	3.57	\$/mmbtu[3]
Crude	1	Forward crude price	77.31	83.90	83.58	\$/barrel
NGL	48	Forward NGL price	0.50	1.33	0.70	\$/gallon
Power	(144)	Forward power price	33.25	76.84	54.44	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(22)	Forward gas price	1.79	4.85	3.39	\$/mmbtu[3]
Crude	123	Forward crude price	33.71	107.48	62.95	\$/barrel
NGL	26	Forward NGL price	0.07	1.40	0.81	\$/gallon
Commodity options[2]						
Crude	36	Option volatility	27%	40%	32%	
NGL	88	Option volatility	19%	94%	39%	
	149					

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:

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(164)**	(24)
Total gains/(loss)		
Included in earnings[1]	**252**	(100)
Included in OCI	**32**	-
Settlements	**29**	(40)
Level 3 net derivative liability at end of period	**149**	(164)

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 December 31, 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 December 31, 2014 (2013 - $103 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $323 million as at December 31, 2014 (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 December 31, 2014, the fair value of this preferred share investment approximates its face value of $580 million (2013 - $580 million).

As at December 31, 2014, the Company's long-term debt had a carrying value of $34,427 million (2013 - $25,168 million) and a fair value of $36,637 million (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 year ended December 31, 2014, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of $199 million (2013 - unrealized loss of $46 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of $114 million (2013 - unrealized loss of $80 million) in OCI. The Company also recognized a realized gain of $10 million (2013 - realized gain of $15 million) in OCI associated with the settlement of foreign exchange forward contracts that had matured during the period. There was no ineffectiveness during the year ended December 31, 2014 (2013 - nil).

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**2,173**	613	1,186
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**326**	92	178
Increase/(decrease) resulting from:			
Provincial and state income taxes	**(36)**	(1)	97
Foreign and other statutory rate differentials[1]	**394**	45	(69)
Effects of rate-regulated accounting[5]	**(97)**	(55)	(38)
Foreign allowable interest deductions[5]	**(65)**	(39)	(24)
Part VI.1 tax, net of federal Part I deduction[2,5]	**47**	23	19
Intercompany sale of investment[3,5]	**68**	-	33
Noncontrolling interests[5]	**(28)**	26	(32)
Other[4,5]	**2**	32	7
Income taxes on earnings before discontinued operations	**611**	123	171
Effective income tax rate	**28.1%**	20.1%	14.4%

1 The higher effective income tax rate for 2014 reflected the increase in earnings in the Company's United States operations and the higher United States federal statutory rate over the Canadian federal statutory rate.

2 Represents Part VI.1 tax on preference share dividend distributions, net of an allowed federal deduction. For 2013, this tax was presented net of an $11 million federal tax recovery related to changes to tax law enacted during the year.

3 In November 2014 and December 2012, Enbridge sold certain assets to the Fund. As these transactions occurred between entities under common control of the Company, the intercompany gains realized on these transfers were eliminated. However, because these transactions involved the sale of shares and partnership units, tax consequences have been recognized in earnings. This resulted in a tax expense of $157 million and $56 million in 2014 and 2012, respectively.

4 Other for 2013 includes $55 million related to the federal component of the tax effect of adjustments related to prior periods.

5 The provincial or state tax component of these items is included in the "Provincial and state income taxes" above.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations			
Canada	**114**	193	1,037
United States	**1,614**	132	(58)
Other	**445**	288	207
	2,173	613	1,186
Current income taxes			
Canada	**35**	(30)	130
United States	**(15)**	18	35
Other	**4**	4	3
	24	(8)	168
Deferred income taxes			
Canada	**(193)**	31	160
United States	**780**	100	(157)
	587	131	3
Income taxes on earnings before discontinued operations	**611**	123	171

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(2,668)**	(1,984)
Investments	**(2,469)**	(1,226)
Regulatory assets	**(240)**	(248)
Other	**(102)**	(115)
Total deferred income tax liabilities	**(5,479)**	(3,573)
Deferred income tax assets		
Financial instruments	**644**	487
Pension and OPEB plans	**203**	128
Loss carryforwards	**390**	129
Other	**246**	68
Total deferred income tax assets	**1,483**	812
Less valuation allowance	**(42)**	(28)
Total deferred income tax assets, net	**1,441**	784
Net deferred income tax liabilities	**(4,038)**	(2,789)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**245**	120
Deferred income taxes	**561**	16
Total deferred income tax assets	**806**	136
Liabilities		
Accounts payable and other	**(2)**	-
Deferred income taxes	**(4,842)**	(2,925)
Total deferred income tax liabilities	**(4,844)**	(2,925)
Net deferred income tax liabilities	**(4,038)**	(2,789)

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2014, the Company recognized the benefit of unused tax loss carryforwards of $826 million (2013 - $322 million) in Canada which start to expire in 2029 and beyond.

As at December 31, 2014, the Company recognized the benefit of unused tax loss carryforwards of $394 million (2013 - $34 million) in the United States which start to expire in 2030 and beyond.

The Company has not provided for deferred income taxes on the difference between the carrying value of substantially all of its foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $4.7 billion (2013 - $2.8 billion). If such earnings are remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Company is subject to potential examinations include the United States (Federal and Texas) and Canada (Federal, Alberta and Ontario). The Company’s 2008 and 2010 to 2014 taxation years are still open for audit in the Canadian and United

States jurisdictions. The Company is currently under examination for income tax matters in Canada for the 2011 and 2012 taxation years, and in the United States for the 2008 and 2010 to 2013 taxation years. The Company is not currently under examination for income tax matters in any other jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**46**	54
Gross increases for tax positions of current year	**5**	10
Gross decreases for tax positions of prior years	**-**	(14)
Reduction for lapse of statute of limitations	**(5)**	(4)
Change in translation of foreign currency	**5**	-
Unrecognized tax benefits at end of year	**51**	46

The unrecognized tax benefits as at December 31, 2014, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income tax expense for the year ended December 31, 2014 included nil (2013 - $5 million recovery; 2012 - $1 million expense) of interest and penalties. As at December 31, 2014, interest and penalties of $5 million (2013 - $5 million) have been accrued.

25. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

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 Canadian Plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The United States Plan provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2014 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2014, the mortality assumption was revised for the United States Plan resulting in an increase to pension liabilities of $21 million. In 2013, the mortality assumptions were revised for the Canadian Plans, resulting in an increase to pension liabilities of $58 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2013	December 31, 2014
Gas Distribution	December 31, 2013	December 31, 2016
United States Plan	January 1, 2014	January 1, 2015

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,903**	1,879	**240**	261
Service cost	**108**	103	**8**	9
Interest cost	**93**	79	**12**	11
Employees' contributions	**-**	-	**1**	1
Actuarial (gains)/loss	**411**	(110)	**16**	(40)
Benefits paid	**(75)**	(75)	**(9)**	(7)
Effect of foreign exchange rate changes	**31**	19	**8**	6
Other	**(1)**	8	**-**	(1)
Benefit obligation at end of year	**2,470**	1,903	**276**	240
Change in plan assets				
Fair value of plan assets at beginning of year	**1,799**	1,500	**81**	62
Actual return on plan assets	**179**	200	**7**	8
Employer's contributions	**138**	155	**11**	12
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(75)**	(75)	**(9)**	(7)
Effect of foreign exchange rate changes	**22**	13	**8**	5
Other	**(1)**	6	**-**	-
Fair value of plan assets at end of year[1]	**2,062**	1,799	**99**	81
Underfunded status at end of year	**(408)**	(104)	**(177)**	(159)
Presented as follows:				
Deferred amounts and other assets	**5**	6	**-**	-
Accounts payable and other	**-**	-	**(6)**	(5)
Other long-term liabilities *(Note 17)*	**(413)**	(110)	**(171)**	(154)
	(408)	(104)	**(177)**	(159)

1 Assets of $32 million (2013 - $27 million) are held by the Company in trust accounts that back non-registered supplemental pension plans benefitting United States plan participants. Due to United States tax regulations, these assets are not restricted from creditors, and therefore the Company is unable to include these balances in plan assets for accounting purposes. However, these assets are committed for the future settlement of non-registered supplemental pension plan obligations included in the underfunded status as at the end of the year.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**4.0%**	5.0%	4.2%	**3.9%**	4.9%	4.0%
Average rate of salary increases	**4.0%**	3.7%	3.7%			

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
(millions of Canadian dollars)						
Benefits earned during the year	**108**	103	84	**8**	9	8
Interest cost on projected benefit obligations	**93**	79	74	**12**	11	10
Expected return on plan assets	**(123)**	(103)	(93)	**(5)**	(4)	(3)
Amortization of prior service costs	**-**	1	2	**-**	-	-
Amortization of actuarial loss	**28**	52	51	**-**	2	2
Net defined benefit costs on an accrual basis	**106**	132	118	**15**	18	17
Defined contribution benefit costs	**4**	4	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**110**	136	122	**15**	18	17
Amount recognized in OCI:						
Net actuarial (gains)/loss[1]	**232**	(158)	42	**15**	(45)	10
Net prior service cost/(credit)[2]	**-**	-	-	**-**	2	-
Total amount recognized in OCI	**232**	(158)	42	**15**	(43)	10
Total amount recognized in Comprehensive income	**342**	(22)	164	**30**	(25)	27

1 *Unamortized actuarial losses included in AOCI, before tax, were $489 million (2013 - $246 million) relating to the pension plans and $26 million (2013 - $11 million) relating to OPEB at December 31, 2014.*

2 *Unamortized prior service costs included in AOCI, before tax, were $6 million (2013 - $6 million) relating to OPEB at December 31, 2014.*

The Company estimates that approximately $28 million related to pension plans and $1 million related to OPEB at December 31, 2014 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*. For the year ended December 31, 2014, an offsetting regulatory liability of $3 million (2013 - $3 million regulatory asset) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**5.0%**	4.2%	4.5%	**4.9%**	4.0%	4.4%
Average rate of return on plan assets	**6.7%**	6.7%	7.1%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.7%	3.5%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.0%	4.4%	2029
Other Medical	4.5%	-	-
United States Plan	7.2%	4.5%	2030

A 1% increase in the assumed medical care trend rate would result in an increase of $37 million in the benefit obligation and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $32 million in the benefit obligation and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
Canadian Plans	**6.7%**	6.6%		
United States Plan	**7.2%**	7.2%	**6.0%**	6.0%

Target Mix for Plan Assets

	Canadian Plans		
	Liquids Pipelines Plan	Gas Distribution Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2014, the pension assets were invested 57.0% (2013 - 58.0%) in equity securities, 32.2% (2013 - 31.0%) in fixed income securities and 10.8% (2013 - 11.0%) in other. The OPEB assets were invested 58.8% (2013 - 59.3%) in equity securities, 40.2% (2013 - 38.3%) in fixed income securities and 1.0% (2013 - 2.4%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $4 million asset (2013 - $1 million asset) and refundable tax assets of $96 million (2013 - $85 million) have been excluded from the table below.

December 31,	2014 Level 1[1]	Level 2[2]	Level 3[3]	Total	2013 Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**42**	**-**	**-**	**42**	42	-	-	42
Fixed income securities								
Canadian government bonds	**121**	**-**	**-**	**121**	99	-	-	99
Corporate bonds and debentures	**4**	**4**	**-**	**8**	3	4	-	7
Canadian corporate bond index fund	**254**	**-**	**-**	**254**	216	-	-	216
Canadian government bond index fund	**198**	**-**	**-**	**198**	167	-	-	167
United States debt index fund	**84**	**-**	**-**	**84**	69	-	-	69
Equity								
Canadian equity securities	**131**	**-**	**-**	**131**	128	-	-	128
United States equity securities	**31**	**-**	**-**	**31**	32	-	-	32
Global equity securities	**11**	**-**	**-**	**11**	11	-	-	11
Canadian equity funds	**255**	**-**	**-**	**255**	216	-	-	216
United States equity funds	**185**	**36**	**-**	**221**	152	33	-	185
Global equity funds	**342**	**134**	**-**	**476**	310	111	-	421
Infrastructure[4]	**-**	**-**	**51**	**51**	-	-	50	50
Real estate[5]	**-**	**-**	**81**	**81**	-	-	76	76
Forward currency contracts	**-**	**(1)**	**-**	**(1)**	-	(6)	-	(6)
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	2	-	-	2
Fixed income securities								
United States government and government agency bonds	**39**	**-**	**-**	**39**	31	-	-	31
Equity								
United States equity funds	**30**	**-**	**-**	**30**	24	-	-	24
Global equity funds	**27**	**-**	**-**	**27**	24	-	-	24

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investments in Bentall Kennedy Prime Canadian Property Fund Ltd. and AEW Core Property Trust are established through the use of valuation models.

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

December 31,	2014	2013
(millions of Canadian dollars)		
Balance at beginning of year	**126**	85
Unrealized and realized gains	**26**	7
Purchases and settlements, net	**(20)**	34
Balance at end of year	**132**	126

Plan Contributions by the Company

Year ended December 31,	Pension 2014	Pension 2013	OPEB 2014	OPEB 2013
(millions of Canadian dollars)				
Total contributions	**138**	155	**11**	12
Contributions expected to be paid in 2015	**109**		**10**	

Benefits Expected to be Paid by the Company

Year ended December 31,	2015	2016	2017	2018	2019	2020-2024
(millions of Canadian dollars)						
Expected future benefit payments	93	99	106	113	120	720

26. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(400)**	(272)	71
Allowance for equity funds used during construction	**3**	1	1
Interest income on affiliate loans	**20**	23	20
Interest income	**3**	4	7
Noverco preferred shares dividend income	**42**	40	42
Gain on disposition *(Note 6)*	**38**	18	-
OPEB recovery *(Note 5)*	**-**	-	89
Other	**28**	51	8
	(266)	(135)	238

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Accounts receivable and other	**(91)**	(789)	(122)
Accounts receivable from affiliates	**(176)**	(53)	43
Inventory	**(186)**	(315)	42
Deferred amounts and other assets	**(431)**	(25)	(380)
Accounts payable and other	**(829)**	832	(319)
Accounts payable to affiliates	**34**	46	(48)
Interest payable	**24**	25	15
Other long-term liabilities	**(66)**	(130)	109
	(1,721)	(409)	(660)

28. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million for the year ended December 31, 2014 (2013 - $6 million; 2012 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution, Gas Pipelines, Processing and Energy Services and Sponsored Investments segments have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to the Company for transportation services for the year ended December 31, 2014 were $256 million (2013 - $222 million; 2012 - $127 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services made natural gas and NGL purchases of $315 million (2013 - $99 million; 2012 - $15 million) from several joint venture affiliates during the year ended December 31, 2014.

Natural gas sales of $58 million (2013 - $10 million; 2012 - $7 million) were made by certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services to several joint venture affiliates during the year ended December 31, 2014.

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector totalling $183 million (2013 - $181 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates ranging from 4% to 8%.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts that primarily relate to the purchase of services, pipe and other materials, as well as transportation, totalling $15,065 million. The amounts which are expected to be paid in the next five years are $5,965 million, $1,815 million, $1,211 million, $986 million and $966 million, respectively, and $4,122 million thereafter.

Minimum future payments under operating leases for buildings, railcars, storage and pipe are estimated at $1,240 million in aggregate. Estimated annual lease payments for the years ending December 31, 2015 through 2019 are $118 million, $114 million, $104 million, $63 million and $61 million, respectively, and $780 million thereafter. Total rental expense for operating leases, included in Operating and administrative expense, were $91 million, $49 million and $31 million for the years ended December 31, 2014, 2013 and 2012, respectively.

ENBRIDGE ENERGY PARTNERS, L.P.

As at December 31, 2014, Enbridge holds an approximate 33.7% (2013 - 20.6%; 2012 - 21.8%) combined direct and indirect economic interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the EPA 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.

As of December 31, 2014, regulatory authority transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at December 31, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($193 million after-tax attributable to Enbridge), which is an increase of US$86 million ($12 million after-tax attributable to Enbridge) as compared with December 31, 2013. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. The total cost increase of US$86 million during the year ended December 31, 2014, is primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake and 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 December 31, 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.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

As at December 31, 2014, the total estimated cost for the Line 6A crude oil release is now approximately US$51 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties, which is an increase of US$3 million (nil after-tax attributable to Enbridge) as compared to December 31, 2013 primarily due to additional legal expenses. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

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 which is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP's remediation spending through December 31, 2014, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at December 31, 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 seven 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 December 31, 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 (PHMSA), 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 further measures directed toward enhancing spill prevention, leak detection, emergency response to environmental events. The cost of compliance with such measures could be significant. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

One claim related to Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the PHMSA on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, EEP received a letter from the PHMSA approving its request to continue the normal operation of Line 14 without pressure restrictions.

The total estimated cost for the repair and remediation associated with the Line 14 crude oil release remains at approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenues and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

AUX SABLE

Notice of Violation

In September 2014, Aux Sable received a Notice of Violation (NOV) from the EPA for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the NOV, Aux Sable discovered what it believes to be additional exceedance of currently permitted limits for Volatile Organic Material. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact, if any, which might result from discussions with the EPA.

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.

30. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

The Company has also agreed to indemnify the Fund for certain liabilities relating to environmental matters arising from operations prior to the transfer of certain crude oil storage assets to the Fund in 2012 and to pay defined payments to the Fund on their investment in Southern Lights in the event shippers do not elect to extend their current contracts post June 2025.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties and affiliates. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities. The Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties and affiliates under these agreements; however, historically, the Company has not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

31. SUBSEQUENT EVENTS

On January 2, 2015, Enbridge transferred its 66.7% interest in the United States segment of the Alberta Clipper pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP for aggregate consideration $1.1 billion (US$1 billion), consisting of approximately $814 million (US$694 million) of Class E equity units issued to Enbridge by EEP and the repayment of approximately $359 million (US$306 million) of indebtedness owed to Enbridge. Prior to the transfer, EEP owned the remaining 33.3% interest in the United States segment of the Alberta Clipper pipeline.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A units held by the public and are convertible into Class A units on a one-for-one basis at Enbridge's option. However, the Class E units are not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at EEP's option after 30 years, if not converted by Enbridge prior to that time. The units have a liquidation preference equal to their notional value at December 23, 2014 of US$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units. Upon closing of the transaction, Enbridge’s economic interest in EEP increased from 33.7% to approximately 37% as a result of the transfer.