Enbridge Inc.

First Quarter
Interim Report to Shareholders
For the three months ended March 31, 2014

HIGHLIGHTS

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

- First quarter earnings were $390 million, including the impact of net unrealized non-cash mark-to-market gains and losses
- First quarter adjusted earnings were $492 million or $0.60 per common share
- Enbridge Inc. and Enbridge Energy Partners, L.P. announced the Line 3 Replacement Project, an approximate $7 billion mainline investment program
- Enbridge Inc. continued to execute its long-term funding plan and raised approximately $2.1 billion since the end of 2013 through debt and preferred equity, as well as increased its enterprise-wide general purpose credit facilities to $18.1 billion

CALGARY, ALBERTA – May 7, 2014 – Enbridge Inc. (Enbridge or the Company) (TSX:ENB) (NYSE:ENB) – “Enbridge performed well in the first quarter of 2014, reflecting solid operating results across our businesses,” said Al Monaco, President and Chief Executive Officer. “Adjusted earnings for the first quarter of 2014 were $492 million, or $0.60 per common share. Backed by the successful execution of our organic growth program, including projects recently placed into service and those expected to be completed over the balance of 2014, we are on track to be within our full year adjusted earnings per share guidance range of $1.84 to $2.04 per share.

“During the quarter, we added to our portfolio of commercially secured growth projects, reflecting continued demand for safe and reliable energy infrastructure,” said Mr. Monaco. “In March, we announced the $7 billion Line 3 Replacement Program, the largest project in our Company’s history. This is a very important project for us as it represents a major enhancement of our mainline liquids pipeline system and it comes with significant benefits to our customers. The increased reliability of throughput on our system will provide customers with greater certainty of service to key markets, and aligns well with our number one priority of safety and operational reliability.”

Investments in the Company’s regional oil sands systems and renewable power generation business also added to the Company’s growth portfolio in the first quarter. In January, Enbridge announced the $0.2 billion Sunday Creek Terminal expansion which will improve service in the oil sands and contribute to maintaining Enbridge’s leading position in the region. Earlier in the same month, Enbridge announced the approximate US$0.2 billion investment in the 110-megawatt (MW) Keechi Wind Project (Keechi), located in Jack County, Texas.

“With a commercially secured portfolio of growth projects totalling a record $36 billion, and an additional $5 billion of projects expected to be secured and placed into service by 2017, there is a high degree of transparency that we will deliver average annual earnings per share growth of 10 to 12% to 2017. The secured slate of organically driven projects also provides confidence in our ability to generate industry leading earnings per share growth well beyond 2017.”

Mr. Monaco commented on the Company’s focus on project execution. “In 2014 and 2015, we expect to place into service more than $18 billion of projects to expand capacity and extend market access for our customers,” said Mr. Monaco. “Since 2008, we’ve put over 40 projects into service representing about $18 billion of capital. We continue to build on our proven project management expertise, experience in cost estimation, ability to anticipate challenges and solid on-the-ground execution.

“We’re also working to enhance and strengthen our relationships with project stakeholders. The National Energy Board’s approval in March of the Line 9B Reversal and Line 9B Expansion Project was supported in large part by the extra lengths taken to engage communities along the right of way and to incorporate stakeholder input, which led to further safety enhancements to the project.”

Financing the growth plan also remains a top priority and Enbridge continues to bolster funding and liquidity support. Since the end of 2013, Enbridge has issued $275 million in preference shares, approximately $1.8 billion in medium-term notes and increased its entity-wide general purpose credit facilities by approximately $0.5 billion. Included in the total debt offerings, was a $130 million issuance with a 50-year maturity date, which is a rarity in the Canadian debt capital market. Enbridge also issued a $300 million three-year medium-term note at a coupon rate of 1.9%, the lowest ever by a Canadian corporate issuer.

"Our consistent access to debt and equity markets demonstrates the confidence investors have in Enbridge, our ability to execute on our record growth capital program and the reliability of our business model," Mr. Monaco said.

Results of Operations
Enbridge delivered a strong first quarter in 2014 and the Company is on track to achieve its full year adjusted earnings per share guidance range. Liquids Pipelines performance was slightly below last year as throughput growth on Canadian Mainline, primarily owing to strong supply from western Canada, was offset by lower tolls and the absence of revenues from Line 9B. As part of the Company's Eastern Access program, Line 9B is currently in the process of being reversed and expanded and is expected to return to service later in the year. Higher volumes on the Athabasca mainline and contributions from growth projects, including the Suncor Bitumen Blending facilities completed in 2013, provided a small earnings growth within Regional Oil Sands System.

Enbridge's sponsored vehicles, Enbridge Energy Partners, L.P. (EEP) and Enbridge Income Fund (the Fund), both had strong starts to 2014. EEP's adjusted earnings reflected higher volumes and tolls across the majority of its liquids business. Also contributing to the increase in adjusted earnings were new assets recently placed into service by EEP, in particular the Bakken Expansion and Access programs which enhanced crude oil gathering capabilities on the North Dakota system. Similarly, the Fund also experienced positive contributions from its portion of the Bakken Expansion Program and benefitted from higher wind and solar resources across its renewable energy portfolio.

Enbridge Gas Distribution Inc. (EGD) continued to contribute to Enbridge's reliable business model in the first quarter, with a slight increase in customer base offset by an increase in expenses. EGD is currently operating under interim rates pending review by the Ontario Energy Board of a new five-year Customized Incentive Regulation mechanism.

Adjusted earnings from Energy Services for the first quarter of 2014 were not as favourable as in the exceptionally strong first quarter of 2013. Adjusted earnings were unfavourably affected by narrowing location spreads and less favourable market conditions in certain physical markets, along with realized losses on certain financial contracts intended to hedge physical transportation capacity but which were not effective in doing so. Partially offsetting the decrease were favourable natural gas location differentials which arose due to abnormal winter weather conditions.

The adjusted earnings discussed above excludes the impact of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains and losses from the Company's long-term hedging program, gains on the disposal of non-core assets and investments, as well as certain costs and related insurance recoveries arising from crude oil releases. See *Non-GAAP Measures.*

FIRST QUARTER 2014 OVERVIEW

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

- Earnings attributable to common shareholders increased from $250 million in the first quarter of 2013 to $390 million in the first quarter of 2014. The Company's earnings increased quarter-over-quarter; however, the comparability of the Company's earnings is impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth. Other non-recurring factors which impacted the first quarter of 2014 included a $43 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. Finally, in the first quarter of 2013, the Company recognized an accrual of US$175 million ($24 million after-tax attributable to Enbridge) associated with a United States Environmental Protection Agency order relating to the Line 6B crude oil release.

- Enbridge's adjusted earnings for the first quarter of 2014 and 2013 were $492 million and $488 million, respectively. Liquids Pipelines adjusted earnings were down slightly as lower quarter-over-quarter earnings from Canadian Mainline and Seaway Crude Pipeline System were offset by higher earnings from Regional Oil Sands System. A lower Canadian Mainline International Joint Tariff Residual Benchmark Toll and the absence of revenues from Line 9B were partially offset by higher throughput. In Gas Distribution, EGD adjusted earnings decreased primarily due to timing of a gas transportation cost adjustment related to the first quarter of 2013 which was recorded in the second half of 2013. Excluding the impact of the gas transportation adjustment, EGD adjusted earnings were comparable between quarters. Energy Services results declined in the first quarter of 2014 relative to the exceptionally strong first quarter of 2013 due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, and 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. This was partially offset by an increase in adjusted earnings due to more favourable natural gas location differentials caused by abnormal winter weather conditions. The Company's sponsored vehicles, EEP and the Fund, both realized strong operating results from their core assets in the first three months of 2014. EEP adjusted earnings reflected higher throughput and tolls on EEP's major liquids pipelines, contributions from assets recently placed into service and the impact of Enbridge's May 2013 investment in preferred units of EEP. Adjusted earnings for the Fund reflected primarily stronger wind and solar resources on the majority of the Fund's renewable energy assets, higher earnings from new assets placed into service and the absence of a write-off of a regulatory deferral balance which occurred in the first quarter of 2013.

- On March 3, 2014, Enbridge and EEP announced that shipper support was received for an approximate $7 billion investment in their Canadian and United States mainline system running from Edmonton, Alberta to Superior, Wisconsin (collectively, 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. EEP will undertake the United States portion of the Line 3 Replacement Program (U.S. L3R Program) which will replace approximately 576-kilometres (358-miles) of pipeline between Neche, North Dakota and Superior. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 barrels per day. Subject to finalization of a definitive cost estimate, regulatory and other approvals, the Canadian L3R Program and the U.S. L3R Program are targeted to be completed in the second half of 2017 at estimated capital costs of approximately $4.2 billion and US$2.6 billion, respectively. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement, while 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. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization.

- On January 29, 2014, Enbridge announced it will construct additional facilities at its 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 Canada Resources Corp. 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 a targeted in-service date of 2015.

- On January, 6, 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 project, located in Jack County, Texas, at an investment of approximately US$0.2 billion. RES Americas is constructing the wind project under a fixed price, engineering, procurement and construction agreement. Construction on the project commenced in December 2013, with expected completion in 2015. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year power purchase agreement with Microsoft Corporation.

- Since the end of 2013, the Company completed the following financing transactions:
    - On April 22, 2014, Enbridge issued medium-term notes of $300 million with a three-year maturity through its subsidiary EGD.
    - On March 28, 2014, Enbridge issued medium-term notes of $130 million with a 50-year maturity.
    - On March 13, 2014, Enbridge completed an offering of 11 million Cumulative Redeemable Preference Shares, Series 9, for gross proceeds of $275 million.
    - On March 11, 2014 Enbridge issued medium term notes of $500 million with a three-year maturity, $400 million with a seven-year maturity and $500 million with a 30-year maturity.
    - In the first quarter of 2014, Enbridge increased its enterprise wide-general purpose credit facilities to approximately $18.1 billion.

DIVIDEND DECLARATION

On April 23, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2014 to shareholders of record on May 15, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9[1]	$0.24110

1 This first dividend declared for the Preference Shares, Series 9 includes accrued dividends from March 13, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on September 1, 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE MONTHS ENDED MARCH 31, 2014

This Management's Discussion and Analysis (MD&A) dated May 6, 2014 should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three months ended March 31, 2014, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company's Annual Report for the year ended December 31, 2013. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**44**	147
Gas Distribution	**136**	107
Gas Pipelines, Processing and Energy Services	**191**	29
Sponsored Investments	**84**	42
Corporate	**(111)**	(75)
Earnings attributable to common shareholders from continuing operations	**344**	250
Discontinued operations - Gas Pipelines, Processing and Energy Services	**46**	-
Earnings attributable to common shareholders	**390**	250
Earnings per common share	**0.48**	0.32
Diluted earnings per common share	**0.47**	0.31

Earnings attributable to common shareholders were $390 million for the three months ended March 31, 2014, or $0.48 per common share, compared with $250 million or $0.32 per common share, for the three months ended March 31, 2013. The Company's earnings increased quarter-over-quarter, however, the comparability of the Company's earnings is impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth. Other non-recurring factors which impacted the first quarter of 2014 included a $43 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. Finally, in the first quarter of 2013, the Company recognized an accrual of US$175 million ($24 million after-tax attributable to Enbridge) associated with a United States Environmental Protection Agency (EPA) order relating to the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.* Excluding the impact of adjusting items, adjusted earnings for the first quarter of 2014 increased slightly over the first quarter of 2013 due to offsetting factors, as discussed below in *Adjusted Earnings*.

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: expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, and may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service date and expected capital expenditures include: the availability and price of labour and construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction 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 law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Adjusting items referred to as changes in unrealized derivative fair value gains or loss are presented net of amounts realized on the settlement of derivative contracts during the applicable period. Management believes the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company's dividend payout target, and to assess performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliations *for a reconciliation of the GAAP and non-GAAP measures.*

ADJUSTED EARNINGS

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**218**	219
Gas Distribution	**103**	113
Gas Pipelines, Processing and Energy Services	**59**	59
Sponsored Investments	**84**	67
Corporate	**28**	30
Adjusted earnings	**492**	488
Adjusted earnings per common share	**0.60**	0.62

Adjusted earnings were $492 million, or $0.60 per common share, for the three months ended March 31, 2014 compared with $488 million, or $0.62 per common share, for the three months ended March 31, 2013. The following factors impacted adjusted earnings.

- Within Liquids Pipelines, adjusted earnings decreased slightly quarter-over-quarter due to lower contributions from Canadian Mainline and Seaway Crude Pipeline System (Seaway Pipeline) offset by a slight increase in adjusted earnings from Regional Oil Sands System. Canadian Mainline adjusted earnings reflected a lower quarter-over-quarter Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll and the absence of revenues from Line 9B, which was idled in late 2013, partially offset by higher throughput. As part of the Company's Eastern Access initiative, Line 9B is being reversed and expanded and is expected to return to service in the fourth quarter of 2014. Seaway Pipeline also experienced higher throughput; however, this was offset by higher financing and administrative costs. Within Regional Oil Sands System, higher throughput on the Athabasca mainline and contributions from the Suncor Bitumen Blending facilities were partially offset by higher operating and administrative, depreciation, interest and tax expenses.
- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings decreased primarily due to the timing of a gas transportation cost adjustment related to the first quarter of 2013 which was recorded in the second half of 2013. Excluding the impact of the gas transportation adjustment, EGD adjusted earnings for the first quarter of 2014 were comparable with the corresponding 2013 period.
- Within Gas Pipelines, Processing and Energy Services, adjusted earnings from Energy Services decreased in the first quarter of 2014 relative to the exceptionally strong first quarter of 2013 primarily due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, and losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. Partially offsetting the decrease was an increase in adjusted earnings due to more favourable natural gas location differentials caused by abnormal winter weather conditions.
- Within Sponsored Investments, adjusted earnings from Enbridge Energy Partners, L.P. (EEP) reflected higher throughput and tolls on EEP's major liquids pipelines, as well as contributions from assets recently placed into service. Also contributing to higher earnings were Enbridge's May 2013

investment in preferred units of EEP. Partially offsetting these positive contributions were lower volumes within EEP's natural gas and NGL businesses.

- Also within Sponsored Investments, Enbridge Income Fund (the Fund) first quarter earnings reflected stronger wind and solar resources on the majority of the Fund's renewable energy assets and higher earnings from the Bakken Expansion. Also positively impacting earnings for the first quarter of 2014 was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013.
- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings decreased in the first quarter of 2014 compared with the first quarter of 2013 due to the impact of a small one-time gain and an equity earnings true-up adjustment, both of which were captured in the first quarter of 2013. Excluding the impacts of these two items, Noverco adjusted earnings increased slightly over the prior quarter due to higher throughput within its gas distribution and power franchise areas.
- Also within the Corporate segment, a smaller Other Corporate loss was recognized due to lower net Corporate segment financing costs, partially offset by higher administrative expense and higher preference share dividends due to an increase in the number of preference shares outstanding.

RECENT DEVELOPMENTS

GAS DISTRIBUTION

Enbridge Gas New Brunswick – Regulatory Matter

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

Also in 2012, the Company commenced legal proceedings against the Government of New Brunswick seeking damages for breach of contract and also commenced a separate application to quash the Government's rate and tariffs regulation. The Company's appeal was ultimately successful, in part, as the Court of Appeal ruled that the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor-in-Council. The Court upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. Following a series of decisions by the New Brunswick Energy and Utilities Board that enabled EGNB to recover its revenue requirement from August 2013 to the next rate period, EGNB filed its 2014 rate application in October 2013. This application was approved in April 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. 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.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. As at March 31, 2014, EEP's total cost estimate for the Line 6B crude oil release remained at US$1,122 million ($181 million after-tax attributable to Enbridge). This total estimate is before insurance recoveries and excludes fines and penalties other than those discussed in *Sponsored Investments – Enbridge Energy Partners, L.P. – Legal and Regulatory Proceedings* below. 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, with the exception of required dredging in and around Morrow Lake and its delta. EEP is in the process of working with the EPA to ensure this work is completed as soon as reasonably possible considering weather conditions.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at March 31, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Including EEP's remediation spending through March 31, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at March 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 for 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.

Of the remaining US$103 million coverage limit, US$85 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing EEP's recovery eligibility for costs related to its claim on the Line 6B oil release. The recovery of the remaining US$18 million is awaiting resolution of this lawsuit. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs which are effective May 1, 2014 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 will increase to US$30 million per event, from the current US$10 million. In the unlikely event multiple insurable incidents occur which exceed coverage limits 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 25 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.

As at March 31, 2014, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by Pipeline and Hazardous Materials Safety Administration that EEP paid during the third quarter of 2012. The total also included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, 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. Discussions with governmental agencies regarding fines and penalties are ongoing.

CORPORATE

Preference Share Issuance

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

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Seaway Crude Pipeline System Twinning/Extension	US$1.1 billion	US$0.8 billion	2014	Under construction
2. Eastern Access[3] Line 9 Reversal and Expansion	$0.4 billion	$0.3 billion	2013-2014 (in phases)	Under construction
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$2.7 billion	US$2.2 billion	2014	Under construction
6. Canadian Mainline Expansion	$0.7 billion	$0.2 billion	2015	Under construction
7. Surmont Phase 2 Expansion	$0.3 billion	$0.1 billion	2014-2015 (in phases)	Under construction
8. Athabasca Pipeline Twinning	$1.2 billion	$0.9 billion	2015	Under construction
9. Edmonton to Hardisty Expansion	$1.8 billion	$0.2 billion	2015	Pre-construction
10. Southern Access Extension	US$0.8 billion	US$0.1 billion	2015	Pre-construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
11. AOC Hangingstone Lateral	$0.1 billion	No significant expenditures to date	2015	Pre-construction
12. Sunday Creek Terminal Expansion	$0.2 billion	$0.1 billion	2015	Under construction
13. Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.2 billion	2013-2015 (in phases)	Under construction
14. Woodland Pipeline Extension	$0.6 billion	$0.2 billion	2015	Pre-construction
15. JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
16. Wood Buffalo Extension	$1.6 billion	No significant expenditures to date	2017	Pre-construction
17. Norlite Pipeline System	$1.4 billion	No significant expenditures to date	2017	Pre-construction
18. Canadian Line 3 Replacement Program	$4.2 billion	No significant expenditures to date	2017	Pre-construction
GAS DISTRIBUTION				
19. Greater Toronto Area Project	$0.7 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
20. Pipestone and Sexsmith Project	$0.3 billion	$0.2 billion	2012-2014 (in phases)	Substantially complete
21. Blackspring Ridge Wind Project	$0.3 billion	$0.3 billion	2014	Under construction
22. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-2015 (in phases)	Under construction
23. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2015	Under construction
24. Keechi Wind Project	US$0.2 billion	US$0.1 billion	2015	Under construction
25. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
SPONSORED INVESTMENTS				
26. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Complete
27. EEP - Eastern Access[4]	US$2.7 billion	US$1.6 billion	2013-2016 (in phases)	Under construction
28. EEP - Lakehead System Mainline Expansion[4]	US$2.3 billion	US$0.3 billion	2014-2016 (in phases)	Under construction
29. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	No significant expenditures to date	2015	Under construction
30. EEP - Sandpiper Project[5]	US$2.6 billion	US$0.1 billion	2016	Pre-construction
31. EEP - U.S. Line 3 Replacement Program	US$2.6 billion	No significant expenditures to date	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 March 31, 2014.*
3 *See* Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Eastern Access *for project discussion.*
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

Seaway Crude Pipeline System

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

Reversal and Expansion

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

Twinning and Extension

Based on additional capacity commitments from shippers, a second line is being constructed that is expected to more than double the existing capacity of the Seaway Pipeline to approximately 850,000 bpd in the second quarter of 2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. 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 137-kilometre (85-mile) pipeline is being 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 will provide capacity of 750,000 bpd and is expected to be available in mid-2014.

Including the acquisition of the initial 50% interest, Enbridge's total expected cost for the Seaway Pipeline is approximately US$2.4 billion. The acquisition, reversal and expansion were completed at an approximate cost of US$1.3 billion, with the twinning, extension and lateral components of the project expected to cost approximately US$1.1 billion. Total expenditures incurred to date are approximately US$2.1 billion.

Eddystone Rail Project

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

Norealis Pipeline

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

Flanagan South Pipeline Project

The 950-kilometre (590-mile) Flanagan South Pipeline will have an initial capacity of approximately 600,000 bpd to transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline is being installed adjacent to the Company's Spearhead Pipeline for the majority of the route. Subject to regulatory and other approvals, the pipeline is expected to be placed into service in the third quarter of 2014. The estimated cost of the project is now approximately US$2.7 billion, with expenditures to date of approximately US$2.2 billion.

The Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court) in August 2013. The Complaint was filed against multiple federal agencies (the Defendants) and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. Enbridge obtained intervener 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 federal agencies, but no decision has yet been released.

Canadian Mainline Expansion

Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases which involve the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was expected to be placed into service in the third quarter of 2014 at an estimated cost of approximately $0.2 billion.

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 now expected to cost approximately $0.5 billion following the completion of progressing levels of detailed engineering review that form part of the Company's project lifecycle gating controls. The revised estimate reflects 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 now approximately $0.7 billion, with expenditures to date 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 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*.

Surmont Phase 2 Expansion

The Company entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. (ConocoPhillips) and Total E&P Canada Ltd. (the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont's Phase 2 expansion. The Company is constructing two new 450,000 barrel blend tanks and converting an existing tank from blend to diluent service. The expansion is expected to come into service in two phases, with the blended product system expected in the fourth quarter of 2014 and the diluent system expected in the first quarter of 2015. The estimated cost of the project is approximately $0.3 billion with expenditures to date of approximately $0.1 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 of $0.9 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 enter service in 2015, with an initial capacity of approximately 450,000 bpd and expansion potential to 800,000 bpd.

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 end of 2015 at an expected total cost of approximately $1.8 billion. Expenditures incurred to date are approximately $0.2 billion**.**

Southern Access Extension

The Southern Access Extension project will involve the construction of a new 265-kilometre (165-mile) 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 bpd, as well as additional tankage and two new pump stations. Subject to regulatory and other approvals, the project is expected to be placed into service in mid-2015 at an approximate cost of US$0.8 billion, with expenditures to date of approximately US$0.1 billion.

AOC Hangingstone Lateral

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 2015 at an estimated cost of approximately $0.1 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

Sunday Creek Terminal Expansion

In January 2014, the Company announced it will construct additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion includes development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion and a targeted in-service date of 2015.

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 and have varying completion dates from 2013 through 2015. The cost of the project is now expected to be approximately $0.7 billion following the completion of progressing levels of detailed engineering review that form part of the Company's project lifecycle gating controls. 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 $0.2 billion.

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 385-kilometre (228-mile) 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. Enbridge's share of the estimated capital cost of the project is approximately $0.6 billion, with expenditures incurred to date of approximately $0.2 billion. Subject to finalization of scope and a definitive cost estimate, the project has a target in-service date of 2015.

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 approval, Enbridge plans to construct a new 50-kilometre (31-mile) 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge's existing Cheecham Terminal. The project will provide capacity of 40,000 bpd at an estimated cost of approximately $0.1 billion and is expected to enter service in 2016.

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.

Norlite Pipeline System

Enbridge is undertaking the development of Norlite Pipeline System (Norlite), a new industry diluent pipeline to meet the needs of multiple producers in the Athabasca oil sands region. Under the currently envisioned scope, a 20-inch diameter pipeline with an approximate ultimate capacity of up to 280,000 bpd, depending on final scope and hydraulic design, 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. Norlite has the right to access certain existing capacity on Keyera Corp. (Keyera) pipelines between Edmonton and Stonefell and, in exchange, Keyera may elect to participate in the new pipeline infrastructure as a 30% non-operating owner.

If Enbridge is successful in securing additional long term commitments on the proposed Norlite system, the scope of the project could be increased to a 24-inch diameter pipeline system as well as include a potential 40-kilometre (25-mile) lateral pipeline to Enbridge's Norealis Terminal. If upsized to a 24-inch diameter pipeline, Norlite will provide capacity to transport up to 270,000 bpd of diluent from Edmonton into the Athabasca oil sands region, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. 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 announced that shipper support was received for an approximate $7 billion investment in their Canadian and United States mainline system running from Edmonton, Alberta to Superior, Wisconsin (collectively, the L3R Program). The Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) will complement existing integrity programs by replacing approximately 1,084-kilometres (673-miles) of the remaining line segments of the existing Line 3 pipeline between Hardisty, Alberta and Gretna, Manitoba. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

Subject to finalization of a definitive cost estimate, regulatory and other approvals, the Canadian L3R Program is targeted to be completed in the second half of 2017 at an estimated capital cost of approximately $4.2 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 Line 3 Replacement Program refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – United States Line 3 Replacement Program*.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD will undertake the expansion of its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.7 billion, 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 Ontario Energy Board (OEB) approval received in January 2014, construction is targeted to start in late 2014 and completion of the project is expected by the end of 2015.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Pipestone and Sexsmith Project

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities located in the Peace River Arch (PRA) region of northwest Alberta (collectively, Pipestone and Sexsmith). These facilities were either in service (Sexsmith) or under construction (Pipestone) at the time of acquisition. Construction of new gathering lines and NGL handling facilities were substantially completed in April 2014. Enbridge's investment in Pipestone and Sexsmith is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.2 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-megawatt (MW) Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project is being constructed under a fixed price engineering, procurement and construction contract and commercial operations are expected to commence in the second quarter of 2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity will be 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 expected to be approximately $0.3 billion, with expenditures incurred to date of approximately $0.3 billion.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS is expected to be placed into service in the fourth quarter of 2014 and the Big Foot Pipeline portion is expected to be placed into service in the second 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 Oil Pipeline (Big Foot Pipeline), located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion. The Big Foot Pipeline is expected to enter service in the second quarter of 2015.

Keechi Wind Project

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

Heidelberg Lateral Pipeline

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

SPONSORED INVESTMENTS

Line 6B 75-Mile Replacement Program

This 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 Enbridge include a partial reversal of Line 9A, a full reversal and expansion of Line 9B and expansion of the Toledo Pipeline. The reversal of a portion of Line 9A and the expansion of the Toledo Pipeline were completed in 2013. 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. The Line 5 expansion and Line 62 expansion were completed in 2013. The individual projects are further described below.

In 2013, Enbridge completed the reversal of a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Enbridge is also undertaking a full reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec. The Line 9B reversal was expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity within Ontario and Quebec, resulting in the Line 9B capacity expansion project. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion. Subject to evaluation of regulatory conditions, the total costs of the Line 9A and Line 9B projects were expected to be approximately $0.4 billion, with costs incurred to date of approximately $0.3 billion.

Both the Line 9B reversal and Line 9B capacity expansion projects were approved by the National Energy Board (NEB) in March 2014, subject to 30 conditions. The conditions imposed by the NEB and the resultant impact on costs and tolls are currently under discussion with shippers, and may materially impact the scope and cost estimate of the Line 9B reversal and Line 9B capacity expansion projects. Subject to fulfillment of the NEB conditions, both projects are expected to be available for service in the fourth quarter of 2014.

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.

Both the Toledo Pipeline and Line 9 assets are included in the Company's Liquids Pipelines segment.

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 is also replacing additional sections of Line 6B in Indiana and Michigan, including 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 are being 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 is expected to be completed in the third quarter of 2014. The replacement of the Line 6B sections is in addition to the Line 6B 75-mile Replacement Program discussed previously. As a result of more detailed engineering estimates coupled with issues with local ground terrain conditions including tie-ins, the expected cost of the United States mainline expansions is now 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 completion of a detailed engineering estimate and a scope revision that removed a proposed tank, the total cost of the projects is now approximately US$0.3 billion. The projects are expected to be placed into service in 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 now approximately US$2.7 billion, with expenditures to date of approximately US$1.6 billion. The Eastern Access projects, excluding the Toledo Expansion and Line 9 Reversal and Expansion, are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Lakehead System Mainline Expansion

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

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase includes an increase in 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 target in-service dates for the proposed projects are the third quarter of 2014 for the initial phase and 2015 for the second phase. It is now anticipated that obtaining regulatory approval will take longer than originally planned though approval is expected before July 2015. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. The initial phase includes an increase in capacity from 400,000 bpd to 560,000 bpd at an estimated capital cost of approximately US$0.2 billion. EEP also plans to undertake a further expansion of the Southern Access line between Superior and Flanagan to increase capacity from 560,000 bpd to 1,200,000 bpd. Following completion of a more detailed engineering estimate, the second phase of the Southern Access expansion is now expected to cost approximately US$1.2 billion. Both phases of the expansion would require only the addition of pumping horsepower and crude oil tanks at existing sites, with no pipeline construction. The target in-service date for the first phase of the expansion is expected to be in the third quarter of 2014. For the second phase of the expansion, which remains subject to regulatory and other approvals, the pump station expansion is expected to be available for service in 2015, with additional tankage requirements expected to be completed in 2016.

As part of the Light Oil Market Access Program, EEP also plans to expand the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 122-kilometre (76-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 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$0.3 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 Midcoast Energy Partners, L.P. (MEP) are constructing a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a planned natural gas processing capability of 150 mmcf/d and is also expected to produce 8,500 bpd of NGL. The Beckville Plant is expected to be placed into service in the first quarter of 2015 at an estimated cost of approximately US$0.1 billion.

Sandpiper Project

As part of the Light Oil Market Access Program initiative, EEP plans to undertake the Sandpiper project (Sandpiper) which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 bpd of capacity on the twin line between Tioga and Clearbrook with a new 24-inch diameter pipeline and 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$0.1 billion.

Marathon Petroleum Corporation (MPC) has been secured as an anchor shipper for Sandpiper. As part of the arrangement, EEP, through its subsidiary, North Dakota Pipeline Company LLC (NDPC) (formerly known as Enbridge Pipelines (North Dakota) LLC), and Williston Basin Pipeline LLC (Williston), an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of Sandpiper construction and will have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed US$1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper, targeted for early 2016.

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. EEP re-filed its petition with the FERC on February 12, 2014 and is expecting to receive a FERC decision in the summer of 2014. Furthermore, 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. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals.

United States Line 3 Replacement Program

In March 2014, Enbridge and EEP announced that shipper support was received for an approximate $7 billion investment in their Canadian and United States mainline system running from Edmonton, Alberta to Superior, Wisconsin. 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. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

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

GROWTH PROJECTS – OTHER PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway Project (Northern Gateway) involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to transport imported condensate from Kitimat to the Edmonton area and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

On December 19, 2013, the Joint Review Panel (JRP) issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living. The JRP found that the potential economic effects of Northern Gateway on local, regional and national economics would be positive and would likely be significant. The JRP is also of the view that the Company's commitments break new ground by providing an unprecedented level of long-term economic, environmental and social benefits to Aboriginal groups. It 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 found that Northern Gateway provided appropriate and effective opportunities for the public and potentially-affected parties to learn about the project and to provide their views and concerns to the Company. The JRP was satisfied that Northern Gateway considered, and was responsive to, the input it received regarding the design, construction and operation of the project.

The JRP found Northern Gateway applied a careful and precautionary approach to its environmental assessment and that Northern Gateway had presented a level of engineering design information that met, or exceeded, regulatory requirements for a thorough and comprehensive review in terms of whether or not it can construct and operate the project in a safe and responsible manner that protects people and the environment. The JRP found that Northern Gateway followed good engineering practice in determining a route that avoids or minimizes exposure to geohazards, had taken all reasonable steps to design a project that would minimize risks of project malfunctions and accidents due to naturally occurring events and that mandatory and voluntary measures outlined by the Company would reduce the potential for human error to the greatest extent possible.

The JRP also referenced the conclusions of the TERMPOL committee and the evidence of various expert witnesses appearing on behalf of Northern Gateway and the Government of Canada in its assessment of the safety of marine transport and concluded that shipping along the north coast of British Columbia could be accomplished safely the vast majority of the time even in the absence of many of the mitigation measures that would be in place for Northern Gateway. These additional mitigation measures would include reduced vessel speeds, escort tugs, redundant navigational systems and avoiding congestion in the narrower parts of the shipping channels. The JRP noted Northern Gateway's commitments represent a substantial increase in spill response capabilities beyond those required by existing legislation and currently existing on the west coast of British Columbia, that they are based on international best practice and continual advances in technology and spill response planning. The JRP included an appendix with 209 conditions that the JRP recommended be included in any certificate that was issued.

The JRP recommended to the Governor in Council that certificates of public convenience and necessity 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 is now consulting with Aboriginal groups on the JRP report and its recommendations prior to making a decision on whether to direct the NEB to issue the certificates for the pipelines. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. The Governor in Council's decision is expected in June 2014.

The cost estimate included in the Northern Gateway filing with the JRP reflects a preliminary estimate prepared in 2004 and escalated to 2010. A detailed estimate based on full engineering analysis of the pipeline route and terminal location is currently being prepared. The detailed estimate will reflect a larger proportion of high cost terrain, longer tunnelling requirements and more extensive terminal site rock excavation than provided for in the preliminary estimate, which is expected to result in a significant increase in the cost estimate.

Five applications for judicial review have been filed with the Federal Court and the Federal Court of Appeal; three from Aboriginal groups and two from environmental groups. The applications seek to set aside the findings of the JRP and prohibit the Federal Government from taking any action to enable the project to proceed. As advocated by Northern Gateway, the Federal Court of Appeal ruled that it has sole jurisdiction over these appeals. Four of the five applications to the Federal Court have been withdrawn, and the fifth applicant has agreed to do so. The applications before the Federal Court of Appeal have also been consolidated into a single proceeding.

Subject to continued commercial support, regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service in 2018 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.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.4 billion, of which approximately half is being funded by potential shippers on Northern Gateway. Given the many uncertainties surrounding Northern Gateway, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

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

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Canadian Mainline	**141**	143
Regional Oil Sands System	**42**	41
Southern Lights Pipeline	**12**	12
Seaway Pipeline	**10**	13
Spearhead Pipeline	**9**	9
Feeder Pipelines and Other	**4**	1
Adjusted earnings	**218**	219
Canadian Mainline - changes in unrealized derivative fair value loss	**(172)**	(72)
Regional Oil Sands System - make-up rights adjustment	**(2)**	-
Earnings attributable to common shareholders	**44**	147

Canadian Mainline

Canadian Mainline adjusted earnings for the three months ended March 31, 2014 decreased slightly compared with the first quarter of 2013. Positively impacting adjusted earnings were higher throughput supported by increased oil sands production, volumes diverted from competing systems and strong refinery demand in the midwest market, although the latter driver was not as significant as expected due to a delay in the start-up of a refinery conversion to heavy oil. Lower operating and administrative costs in the first quarter of 2014 were also positive factors relative to the comparative period.

Offsetting these positive impacts was a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher due to the recovery of incremental costs associated with EEP's growth projects. Higher power costs associated with incremental throughput as well as higher depreciation from an increased asset base also impacted adjusted earnings for the quarter. Finally, adjusted earnings for the first quarter of 2014 were 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. Canadian Mainline earnings would have been slightly higher than the very strong first quarter of 2013 but for the temporary idling of Line 9B. Line 9B is expected to resume service in the fourth quarter of 2014. For further information on Line 9B refer to *Growth Projects – Commercially Secured Projects – Sponsored Investment – Enbridge Energy Partners, L.P. – Eastern Access.*

As discussed above, the Canadian Mainline IJT Residual Benchmark Toll is inversely impacted by changes in the Lakehead System Toll. EEP has delayed its annual April 1 tariff filing for its Lakehead System as it is currently in negotiations with the Canadian Association of Petroleum Producers (CAPP) concerning certain components of the tariff rate structure. EEP expects to file revised rates in May with an effective date of July 1, 2014. This filing will adjust the rates to reflect any agreed upon changes in the tariff rate structure.

Supplemental information on Canadian Mainline adjusted earnings for the three months ended March 31, 2014 and 2013 is as follows:

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Revenues	**373**	387
Expenses		
Operating and administrative	**83**	99
Power	**38**	29
Depreciation and amortization	**66**	58
	187	186
	186	201
Other income	**1**	-
Interest expense	**(40)**	(40)
	147	161
Income taxes	**(6)**	(18)
Adjusted earnings	**141**	143
Effective United States to Canadian dollar exchange rate[1]	**1.02**	1.00

March 31,	**2014**	2013
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$3.98**	$3.94
Lakehead System Local Toll[3]	**$2.17**	$1.85
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.81**	$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, 2013, the IJT Benchmark Toll increased from US$3.94 to US$3.98.*

3 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2013, this toll increased from US$1.85 to US$2.13 and further increased from US$2.13 to US$2.18 effective July 1, 2013. Effective January 1, 2014, this toll decreased to US$2.17.*

4 *The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. Effective April 1, 2013, this toll decreased from US$2.09 to US$1.81 and further decreased from US$1.81 to US$1.80. Effective January 1, 2014, this toll increased to US$1.81. For any shipment, this toll is the difference between the IJT Benchmark Toll for that shipment and the Lakehead System Local Toll for that shipment.*

	Three months ended March 31,	
	2014	2013
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,904**	1,783

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

Regional Oil Sands System
Regional Oil Sands System adjusted earnings for the three months ended March 31, 2014 were slightly higher compared with the first quarter of 2013. Positively impacting earnings growth were higher throughput on the Athabasca mainline and higher tankage revenues from the Suncor Bitumen Blending facilities placed into service in the second quarter of 2013. Partially offsetting the increase in earnings were higher depreciation expense from a larger asset base and higher operating and administrative, interest and tax expenses.

Seaway Pipeline
Seaway Pipeline earnings decreased for the three months ended March 31, 2014 compared with the first three months of 2013. Higher financing and administrative costs and higher power costs were partially offset by higher volumes on Seaway Pipeline.

Feeder Pipelines and Other
The earnings increase in Feeder Pipelines and Other primarily reflected lower business development costs.

Liquids Pipelines earnings were impacted by the following adjusting items:
- Canadian Mainline earnings/(loss) for each period reflected changes in unrealized fair value losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Regional Oil Sands System earnings for 2014 included an adjustment to recognize revenues for certain long-term take-or-pay contracts ratably over the contract life. Make-up rights are earned 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. As such, adjusted earnings reflect contributions from these contracts ratably over the life of the contract, consistent with contractual cash payments under the contract.

GAS DISTRIBUTION

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**91**	100
Other Gas Distribution and Storage	**12**	13
Adjusted earnings	**103**	113
EGD - (warmer)/colder than normal weather	**33**	(6)
Earnings attributable to common shareholders	**136**	107

EGD is currently operating under OEB approved interim distribution rates pending a final decision by the OEB on EGD's application for a five-year Customized Incentive Regulation rate-setting mechanism with an effective date of January 1, 2014. Under the proposed application, EGD expects to be permitted to adjust its rates for the difference in revenues under interim rates and final 2014 rates. A final decision is anticipated in the third quarter of 2014.

EGD adjusted earnings decreased in the first quarter of 2014 compared with the comparative 2013 period primarily due to timing of a gas transportation cost adjustment related to the first quarter of 2013 which was recorded in the second half of 2013. Excluding the impact of the gas transportation adjustment, EGD adjusted earnings for the first quarter of 2014 were comparable with the equivalent 2013 period as customer growth and lower operating and administrative expense were offset by higher depreciation expense due to the growth in asset base and lower transactional services revenues. Transactional services opportunities were limited in the first quarter of 2014 because high volume throughput, as a result of a colder than normal winter, limited the pipeline capacity available for optimization activity.

Adjusted earnings from Other Gas Distribution and Storage for the first quarter of 2014 included a loss from EGNB related to one contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received. This contract expires in the fourth quarter of 2014 and is not expected to have a significant impact to adjusted earnings for the remainder of the year.

Gas Distribution earnings were impacted by the following adjusting item:
- EGD earnings were adjusted to reflect the impact of weather.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Aux Sable	**7**	8
Energy Services	**24**	33
Alliance Pipeline US	**12**	10
Vector Pipeline	**6**	7
Enbridge Offshore Pipelines (Offshore)	**4**	2
Other	**6**	(1)
Adjusted earnings	**59**	59
Energy Services - changes in unrealized derivative fair value gains/(loss)	**136**	(30)
Offshore - gain on sale of non-core assets	**43**	-
Other - changes in unrealized derivative fair value loss	**(1)**	-
Earnings attributable to common shareholders	**237**	29

Energy Services operates a physical commodity marketing business which captures value from quality, time and location differentials when opportunities arise. To execute these strategies Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines. Adjusted earnings decreased in the first quarter of 2014 relative to the exceptionally strong first quarter of 2013 primarily due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, and losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. Partially offsetting the decrease was an increase in adjusted earnings due to more favourable natural gas location differentials caused by abnormal winter weather conditions. Adjusted earnings from Energy Services are dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Alliance Pipeline US earnings increased in the first quarter of 2014 compared with the first quarter of 2013 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.

The decrease in Vector Pipeline earnings in the first quarter of 2014 compared with the corresponding three month period of 2013 reflected lower depreciation expense recognized in tolls, partially offset by higher uncommitted transportation volumes coupled with higher prices. Higher volumes were primarily driven by increased demand for natural gas in eastern North America in response to abnormal winter weather conditions experienced in the first quarter of 2014.

Offshore adjusted earnings increased slightly in the first quarter of 2014 compared with the first quarter of 2013. The increase primarily reflected contributions from the Venice Condensate Stabilizer Expansion placed into service in November 2013 and cost savings achieved from the Company's decision not to renew windstorm insurance coverage effective May 2013.

The increase in earnings from Other was primarily attributable to new assets placed into service in 2013, including the 50% interest in the Lac Alfred Wind Farm which placed an additional 150-MW of power generation capacity into service in August 2013.

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

- Energy Services earnings for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory. A gain or loss on such a financial derivative corresponds to a similar but opposite loss or gain on the value of the underlying physical transaction which is expected to be realized in the future when the physical transaction settles. Unlike the change in the value of the financial derivative, the gain or loss on the value of the underlying physical transaction is not recorded for financial statement purposes until the periods in which it is realized.
- Offshore earnings for the first quarter of 2014 included a gain from the disposal of non-core assets.
- Other earnings for the first quarter of 2014 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.

SPONSORED INVESTMENTS

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Enbridge Energy Partners, L.P. (EEP)	**45**	36
Enbridge Energy, Limited Partnership (EELP)	**7**	8
Enbridge Income Fund (the Fund)	**32**	23
Adjusted earnings	**84**	67
EEP - leak remediation costs	**-**	(24)
EEP - changes in unrealized derivative fair value loss	**-**	(1)
Earnings attributable to common shareholders	**84**	42

EEP adjusted earnings increased in the first quarter of 2014 compared with the corresponding 2013 period. Adjusted earnings increased in EEP's liquids business due to higher throughput and tolls on EEP's major liquids pipelines, as well as contributions from assets recently placed into service. New assets contributing to the increase included the Bakken Expansion and Access programs, which enhanced crude oil gathering capabilities on the North Dakota system, and the recently completed Lakehead System Line 6B 75-mile replacement program. Partially offsetting the increase in adjusted earnings in EEP's liquids business were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base. Also contributing to higher earnings in the first quarter of 2014 was Enbridge's May 2013 investment in preferred units of EEP. Finally, the first quarter of 2014 reflected lower volumes within EEP's natural gas and NGL businesses, which it holds directly and indirectly through its partially owned subsidiary, MEP.

EEP has delayed its annual April 1 tariff filing for its Lakehead System as it is currently in negotiations with the CAPP concerning certain components of the tariff rate structure. EEP expects to file revised rates in May with an effective date of July 1, 2014. This filing will adjust the rates to reflect any agreed upon changes in the tariff rate structure.

Earnings for the Fund for the first quarter of 2014 were higher compared with the corresponding 2013 period and reflected strong performance across the Fund's diverse businesses. Among the positive contributors were stronger wind and solar resources on the majority of the Fund's renewable energy assets and higher earnings from the Bakken Expansion which was placed into service in March 2013. Also positively impacting earnings for the first quarter of 2014 was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013.

Sponsored Investments earnings were impacted by the following adjusting items:

- Earnings from EEP for the first quarter of 2013 included a charge related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*
- Earnings from EEP for the first quarter of 2013 included a change in the unrealized fair value loss on derivative financial instruments.

CORPORATE

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Noverco	**29**	39
Other Corporate	**(1)**	(9)
Adjusted earnings	**28**	30
Noverco - changes in unrealized derivative fair value gains/(loss)	**(4)**	1
Other Corporate - changes in unrealized derivative fair value loss	**(149)**	(105)
Other Corporate - gain on sale of investment	**14**	-
Other Corporate - foreign tax recovery	**-**	4
Other Corporate - impact of tax rate changes	**-**	(5)
Loss attributable to common shareholders	**(111)**	(75)

Noverco adjusted earnings decreased in the first quarter of 2014 compared with the first quarter of 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 in the first quarter of 2013 and an equity earnings true-up adjustment captured in the first quarter of 2013, Noverco adjusted earnings increased slightly over the prior quarter due to higher throughput within its gas distribution and power franchise areas.

Other Corporate adjusted loss decreased in the first quarter of 2014 and reflected lower net Corporate segment financing costs, partially offset by higher administrative expense and higher preference share dividends due to an increase in the number of preference shares outstanding.

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

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the record level of growth projects secured or under development. The Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company's longer-term financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles, with the objective of diversifying funding sources and maintaining access to low cost capital.

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

- Corporate - $275 million preference shares; $1,530 million medium-term notes; and
- EGD - $300 million medium-term notes.

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

		March 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**156**	**144**	300
Gas Distribution	2015-2019	**708**	**708**	**-**	713
Sponsored Investments	2015-2018	**4,949**	**1,242**	**3,707**	4,781
Corporate	2015-2018	**12,158**	**4,299**	**7,859**	11,805
		18,115	**6,405**	**11,710**	17,599
Southern Lights project financing[1]	2014-2015	**1,617**	**1,543**	**74**	1,570
Total committed credit facilities		**19,732**	**7,948**	**11,784**	19,169

1 Total facilities inclusive of $65 million for debt service reserve letters of credit.
2 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

In addition to the committed credit facilities noted above, the Company also has $277 million of uncommitted demand credit facilities, of which $228 million was unutilized as at March 31, 2014.

Subsequent to quarter end, EGD issued $300 million of medium-term notes and a portion of the proceeds were used to repay credit facility draws outstanding as at March 31, 2014.

Excluding project financing, the Company's net available liquidity of $12,189 million at March 31, 2014 was inclusive of $849 million of unrestricted cash and cash equivalents and net of bank indebtedness of $370 million.

There are no material restrictions on the Company's cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $22 million for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

OPERATING ACTIVITIES

Cash provided by operating activities for the three months ended March 31, 2014 was $333 million compared with $793 million for the three months ended March 31, 2013. Excluding the timing effect of changes in operating assets and liabilities, the Company delivered growth in cash flow period-over-period.

This cash flow growth was attributable in part to the completion of significant growth projects in recent years. The 2013 additions in Regional Oil Sands System, Offshore and renewable energy assets and the completion of Bakken Expansion, as discussed in *Financial Results*, have contributed to the increase in period-over-period operating cash flows. Also contributing to this cash growth were higher contributions from the Company's gas distribution business due to unusually cold weather, as well as higher distributions from the Company's equity investments.

The Company’s operating assets and liabilities fluctuate due to variations in weather, commodity price differentials and sales volumes within Energy Services and Gas Distribution businesses, as well as general variations in activity levels within the Company’s businesses. The period-over-period decrease in cash provided by operating activities for the three months ended March 31, 2014 was impacted by a negative variance of $658 million for changes in operating assets and liabilities. The variance is mainly attributable to the Company’s operating growth and significantly higher natural gas prices combined with colder weather within the Company’s gas distribution business, which increased short-term working capital requirements.

At March 31, 2014, the Company had a negative working capital position mainly attributable to a period-over-period increase in short term debt, which temporarily funded growth capital expenditures. This was partially offset by an increase in net operating assets and liabilities as described above. Despite this negative working capital, the Company has significant net available liquidity through committed credit facilities, which allow the funding of liabilities as they become due. As at March 31, 2014, the net available liquidity totalled $12,189 million (December 31, 2013 - $12,909 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

INVESTING ACTIVITIES

Cash used in investing activities was $2,743 million for the three months ended March 31, 2014 compared with $1,643 million for the three months ended March 31, 2013. Cash used in investing activities has increased on a period-over-period basis primarily due to additions to property, plant and equipment associated with construction of the Company's growth projects which are further described in *Growth Projects – Commercially Secured Projects*. Cash used in investing activities in the first quarter of 2014 also included the funding of various investments and joint ventures, primarily the Seaway Pipeline Twinning/Extension project.

FINANCING ACTIVITIES

The Company continues to execute its funding and liquidity strategy in support of its long-term growth plan. In the first quarter of 2014, cash generated from financing activities was $2,465 million compared with $420 million in the first quarter of 2013. During the first three months of 2014, the Company raised net proceeds of $1,812 million (2013 - $421 million) through capital markets transactions, including $1,528 million (2013 - nil) of medium-term notes, $268 million (2013 - $399 million) in preference shares and $16 million (2013 - $22 million) in common shares through routine exercises of stock options. The Company also bolstered its liquidity during the first quarter of 2014 through the securement of additional credit facilities, and increased draws on total available facilities and commercial paper issuances by $459 million over the prior quarter. A portion of the increased draws was attributable to financing working capital requirements at EGD, which increased due to higher distribution volumes during the abnormally cold first quarter of 2014.

Additional preference and common shares outstanding during the quarter gave rise to an increase in the dividends paid during the first three months of 2014 compared with the same period of 2013, partially offsetting the financing activities inflows.

Also impacting cash flows from financing activities were the transactions between the Company’s sponsored vehicles and their public unit holders. During the first quarter of 2014, EEP, MEP and the Fund made distributions, net of contributions, of $107 million to their public unit holders. In the first quarter of 2013, sponsored vehicles received contributions, net of distributions, of $234 million primarily as a result of their equity issuances to the public.

Participants in the Company’s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended March 31, 2014, dividends declared were $291 million (2013 - $254 million), of which $185 million (2013 - $164 million) were paid in cash and reflected in financing activities. The remaining $106 million (2013 - $90 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three months ended March 31, 2014, 36.4% (2013 - 35.4%) of total dividends declared were reinvested.

On April 23, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2014 to shareholders of record on May 15, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9[1]	$0.24110

1 This first dividend declared for the Preference Shares, Series 9 includes accrued dividends from March 13, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on September 1, 2014. See Recent Developments – Corporate – Preference Share Issuance*.*

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $2,650 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, certain revenues denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy whereby it economically hedges a minimum level of foreign currency denominated earnings exposures identified over a five-year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales and foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues denominated in United States dollars.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 1.9%.

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 2017. A total of $9,543 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.6%.

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

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

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

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

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

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**29**	14
Interest rate contracts	**(242)**	79
Commodity contracts	**(7)**	-
Other contracts	**5**	2
Net investment hedges		
Foreign exchange contracts	**(48)**	(22)
	(263)	73
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Foreign exchange contracts[1]	**(1)**	-
Interest rate contracts[2]	**21**	13
Commodity contracts[3]	**7**	-
Other contracts[4]	**(4)**	-
	23	13
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**25**	38
Commodity contracts[3]	**1**	(1)
	26	37
Amount of gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts[1]	**(420)**	(193)
Interest rate contracts[2]	**1**	(4)
Commodity contracts[3]	**173**	(53)
Other contracts[4]	**5**	6
	(241)	(244)

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

LIQUIDITY RISK

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

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

FAIR VALUE MEASUREMENTS

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

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

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

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued revised "base case assumptions" based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On November 29, 2011, as required by the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc. and

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

All applications by the Company will require NEB approval. The NEB hearings commenced January 14, 2014, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. A decision is expected in the second quarter of 2014.

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.

During the three months ended March 31, 2014, the Company recognized ARO in the amount of $162 million. Of this amount, $66 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur in 2014 and $96 million related to the Canadian and United States portions of the L3R Program announced in March 2014.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

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

Parent's Accounting for the Cumulative Translation Adjustment

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

FUTURE ACCOUNTING POLICY CHANGES

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. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

QUARTERLY FINANCIAL INFORMATION

	2014	2013				2012		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**10,521**	8,293	8,998	7,730	7,897	7,007	5,676	5,445
Earnings attributable to common shareholders	**390**	(267)	421	42	250	146	187	8
Earnings per common share	**0.48**	(0.33)	0.52	0.05	0.32	0.19	0.24	0.01
Diluted earnings per common share	**0.47**	(0.32)	0.51	0.05	0.31	0.18	0.24	0.01
Dividends per common share	**0.3500**	0.3150	0.3150	0.3150	0.3150	0.2825	0.2825	0.2825
EGD - warmer/(colder) than normal weather	**(33)**	(13)	-	(2)	6	(1)	-	-
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**190**	613	(223)	246	207	81	93	252

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

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

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

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

- First quarter earnings for 2014 included a $43 million after-tax gain on the disposal of non-core Offshore assets and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.
- Included in earnings are after-tax costs of $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.
- Reflected in earnings is the Company's share of leak remediation costs associated with the Line 6B and Line 14 crude oil releases. Remediation costs of $24 million, $6 million, $5 million and $9 million were recognized in the first, second, third and fourth quarters of 2013; $2 million and $7 million in the second and third quarters of 2012, respectively. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013 and $24 million in the third quarter of 2012, respectively.
- Fourth quarter earnings for 2012 included a $63 million, after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.
- Also included in the fourth quarter earnings for 2012 was an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors.

- Fourth quarter earnings for 2012 also included the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million incurred on the related capital gain.

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

NON-GAAP RECONCILIATIONS

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Earnings attributable to common shareholders	**390**	250
Adjusting items:		
Liquids Pipelines		
Canadian Mainline - changes in unrealized derivative fair value loss	**172**	72
Regional Oil Sands System - make-up rights adjustment	**2**	-
Gas Distribution		
EGD - warmer/(colder) than normal weather	**(33)**	6
Gas Pipelines, Processing and Energy Services		
Energy Services - changes in unrealized derivative fair value (gains)/loss	**(136)**	30
Offshore - gain on sale of non-core assets	**(43)**	-
Other - changes in unrealized derivative fair value loss	**1**	-
Sponsored Investments		
EEP - leak remediation costs	**-**	24
EEP - changes in unrealized derivative fair value loss	**-**	1
Corporate		
Noverco - changes in unrealized derivative fair value (gains)/loss	**4**	(1)
Other Corporate - changes in unrealized derivative fair value loss	**149**	105
Other Corporate - gain on sale of investment	**(14)**	-
Other Corporate - foreign tax recovery	**-**	(4)
Other Corporate - impact of tax rate changes	**-**	5
Adjusted earnings	**492**	488

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Series A[2]	5,000,000
Preference Shares, Series B[2,3]	20,000,000
Preference Shares, Series D[2,4]	18,000,000
Preference Shares, Series F[2,5]	20,000,000
Preference Shares, Series H[2,6]	14,000,000
Preference Shares, Series J[2,7]	8,000,000
Preference Shares, Series L[2,8]	16,000,000
Preference Shares, Series N[2,9]	18,000,000
Preference Shares, Series P[2,10]	16,000,000
Preference Shares, Series R[2,11]	16,000,000
Preference Shares, Series 1[2,12]	16,000,000
Preference Shares, Series 3[2,13]	24,000,000
Preference Shares, Series 5[2,14]	8,000,000
Preference Shares, Series 7[2,15]	10,000,000
Preference Shares, Series 9[2,16]	11,000,000
Common Shares - issued and outstanding (voting equity shares)	834,811,051
Stock Options - issued and outstanding (19,741,660 vested)	38,082,053

1 Outstanding share data information is provided as at April 25, 2014.

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

3 On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series B will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series B into an equal number of Cumulative Redeemable Preference Shares, Series C.

4 On March 1, 2018, and on March 1 every five years thereafter, the holders of Preference Shares, Series D will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series D into an equal number of Cumulative Redeemable Preference Shares, Series E.

5 On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series F will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series F into an equal number of Cumulative Redeemable Preference Shares, Series G.

6 On September 1, 2018, and on September 1 every five years thereafter, the holders of Preference Shares, Series H will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series H into an equal number of Cumulative Redeemable Preference Shares, Series I.

7 On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series J will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series J into an equal number of Cumulative Redeemable Preference Shares, Series K.

8 On September 1, 2017, and on September 1 every five years thereafter, the holders of Preference Shares, Series L will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series L into an equal number of Cumulative Redeemable Preference Shares, Series M.

9 On December 1, 2018, and on December 1 every five years thereafter, the holders of Preference Shares, Series N will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series N into an equal number of Cumulative Redeemable Preference Shares, Series O.

10 On March 1, 2019, and on March 1 every five years thereafter, the holders of Preference Shares, Series P will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series P into an equal number of Cumulative Redeemable Preference Shares, Series Q.

11 On June 1, 2019, and on June 1 every five years thereafter, the holders of Preference Shares, Series R will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series R into an equal number of Cumulative Redeemable Preference Shares, Series S.

12 On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series 1 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 1 into an equal number of Cumulative Redeemable Preference Shares, Series 2.

13 On September 1, 2019, and on September 1 every five years thereafter, the holders of Preference Shares, Series 3 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 3 into an equal number of Cumulative Redeemable Preference Shares, Series 4.

14 On March 1, 2019, and on March 1 every five years thereafter, the holders of Preference Shares, Series 5 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 5 into an equal number of Cumulative Redeemable Preference Shares, Series 6.

15 On March 1, 2019, and on March 1 every five years thereafter, the holders of Preference Shares, Series 7 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 7 into an equal number of Cumulative Redeemable Preference Shares, Series 8.

16 On December 1, 2019, and on December 1 every five years thereafter, the holders of Preference Shares, Series 9 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 9 into an equal number of Cumulative Redeemable Preference Shares, Series 10.

CONSOLIDATED STATEMENTS OF EARNINGS

(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended March 31, 2014	2013
Revenues		
Commodity sales	**8,006**	5,804
Gas distribution sales	**1,111**	891
Transportation and other services	**1,404**	1,202
	10,521	7,897
Expenses		
Commodity costs	**7,733**	5,612
Gas distribution costs	**846**	666
Operating and administrative	**745**	664
Depreciation and amortization	**366**	322
Environmental costs, net of recoveries *(Note 13)*	**5**	183
	9,695	7,447
	826	450
Income from equity investments	**114**	101
Other expense	**(138)**	(48)
Interest expense	**(238)**	(255)
	564	248
Income taxes *(Note 11)*	**(117)**	(62)
Earnings from continuing operations	**447**	186
Discontinued operations *(Note 4)*		
Earnings from discontinued operations before income taxes	**73**	-
Income taxes from discontinued operations	**(27)**	-
Earnings from discontinued operations	**46**	-
Earnings	**493**	186
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(48)**	103
Earnings attributable to Enbridge Inc.	**445**	289
Preference share dividends	**(55)**	(39)
Earnings attributable to Enbridge Inc. common shareholders	**390**	250
Earnings attributable to Enbridge Inc. common shareholders		
Earnings from continuing operations	**344**	250
Earnings from discontinued operations, net of tax	**46**	-
	390	250
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*		
Continuing operations	**0.42**	0.32
Discontinued operations	**0.06**	-
	0.48	0.32
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*		
Continuing operations	**0.41**	0.31
Discontinued operations	**0.06**	-
	0.47	0.31

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2014	2013
(unaudited; millions of Canadian dollars)		
Earnings	**493**	186
Other comprehensive income/(loss), net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**(304)**	77
Change in unrealized loss on net investment hedges	**(89)**	(24)
Other comprehensive income from equity investees	**4**	2
Reclassification to earnings of realized cash flow hedges	**40**	10
Reclassification to earnings of unrealized cash flow hedges	**20**	28
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**1**	9
Change in foreign currency translation adjustment	**523**	187
Other comprehensive income	**195**	289
Comprehensive income	**688**	475
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(141)**	18
Comprehensive income attributable to Enbridge Inc.	**547**	493
Preference share dividends	**(55)**	(39)
Comprehensive income attributable to Enbridge Inc. common shareholders	**492**	454

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31, 2014	2013
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 8)*		
Balance at beginning of period	**5,141**	3,707
Preference shares issued	**270**	402
Balance at end of period	**5,411**	4,109
Common shares		
Balance at beginning of period	**5,744**	4,732
Dividend reinvestment and share purchase plan	**106**	90
Shares issued on exercise of stock options	**24**	32
Balance at end of period	**5,874**	4,854
Additional paid-in capital		
Balance at beginning of period	**746**	522
Stock-based compensation	**12**	14
Options exercised	**(9)**	(10)
Dilution gains and other	**(4)**	5
Balance at end of period	**745**	531
Retained earnings		
Balance at beginning of period	**2,550**	3,173
Earnings attributable to Enbridge Inc.	**445**	289
Preference share dividends	**(55)**	(39)
Common share dividends declared	**(291)**	(254)
Dividends paid to reciprocal shareholder	**4**	7
Redemption value adjustment attributable to redeemable noncontrolling interests	**(148)**	(83)
Balance at end of period	**2,505**	3,093
Accumulated other comprehensive loss *(Note 9)*		
Balance at beginning of period	**(599)**	(1,762)
Other comprehensive income attributable to Enbridge Inc. common shareholders	**102**	204
Balance at end of period	**(497)**	(1,558)
Reciprocal shareholding - balance at beginning and end of period	**(86)**	(126)
Total Enbridge Inc. shareholders' equity	**13,952**	10,903
Noncontrolling interests		
Balance at beginning of period	**4,014**	3,258
Earnings/(loss) attributable to noncontrolling interests	**45**	(92)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**(70)**	19
Change in foreign currency translation adjustment	**155**	60
Reclassification to earnings of realized cash flow hedges	**10**	5
Reclassification to earnings of unrealized cash flow hedges	**3**	-
	98	84
Comprehensive income/(loss) attributable to noncontrolling interests	**143**	(8)
Contributions	**41**	275
Distributions	**(130)**	(114)
Other	**(2)**	7
Balance at end of period	**4,066**	3,418
Total equity	**18,018**	14,321
Dividends paid per common share	**0.350**	0.315

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2014	2013
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**493**	186
Earnings from discontinued operations	**(46)**	-
Depreciation and amortization	**366**	322
Deferred income taxes	**69**	1
Changes in unrealized loss on derivative instruments, net	**244**	248
Cash distributions in excess of/(less than) equity earnings	**12**	(31)
Gain on disposition	**(16)**	-
Other	**62**	65
Changes in regulatory assets and liabilities	**5**	12
Changes in environmental liabilities, net of recoveries *(Note 13)*	**(46)**	161
Changes in operating assets and liabilities	**(829)**	(171)
Cash provided by continuing operations	**314**	793
Cash provided by discontinued operations *(Note 4)*	**19**	-
	333	793
Investing activities		
Additions to property, plant and equipment	**(2,408)**	(1,457)
Long-term investments	**(313)**	(128)
Additions to intangible assets	**(53)**	(51)
Proceeds from disposition	**19**	-
Affiliate loans, net	**3**	2
Changes in restricted cash	**5**	(9)
Cash provided by continuing operations	**(2,747)**	(1,643)
Cash provided by discontinued operations *(Note 4)*	**4**	-
	(2,743)	(1,643)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**361**	(212)
Net change in commercial paper and credit facility draws	**838**	379
Debenture and term note issues	**1,528**	-
Debenture and term note repayments	**(200)**	(200)
Contributions from noncontrolling interests	**41**	275
Distributions to noncontrolling interests	**(130)**	(114)
Contributions from redeemable noncontrolling interests	**-**	91
Distributions to redeemable noncontrolling interests	**(18)**	(18)
Preference shares issued	**268**	399
Common shares issued	**16**	22
Preference share dividends	**(54)**	(38)
Common share dividends	**(185)**	(164)
	2,465	420
Effect of translation of foreign denominated cash and cash equivalents	**18**	-
Increase/(decrease) in cash and cash equivalents	**73**	(430)
Cash and cash equivalents at beginning of period - discontinued operations	**20**	-
Cash and cash equivalents at beginning of period - continuing operations	**756**	1,776
Cash and cash equivalents at end of period	**849**	1,346

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2014	December 31, 2013
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**849**	756
Restricted cash	**29**	34
Accounts receivable and other *(Note 5)*	**6,284**	4,956
Accounts receivable from affiliates	**66**	65
Inventory	**1,050**	1,115
Assets held for sale *(Note 4)*	**-**	24
	8,278	6,950
Property, plant and equipment, net	**45,323**	42,279
Long-term investments	**4,650**	4,212
Deferred amounts and other assets	**2,629**	2,662
Intangible assets, net	**1,043**	1,004
Goodwill	**462**	445
Deferred income taxes	**150**	16
	62,535	57,568
Liabilities and equity		
Current liabilities		
Bank indebtedness	**370**	338
Short-term borrowings	**703**	374
Accounts payable and other	**7,469**	6,664
Accounts payable to affiliates	**32**	46
Interest payable	**267**	228
Environmental liabilities	**224**	260
Current maturities of long-term debt *(Note 6)*	**3,011**	2,811
Liabilities held for sale *(Note 4)*	**-**	7
	12,076	10,728
Long-term debt *(Note 6)*	**24,714**	22,357
Other long-term liabilities *(Note 7)*	**3,418**	2,938
Deferred income taxes	**3,129**	2,925
Liabilities held for sale *(Note 4)*	**-**	57
	43,337	39,005
Contingencies *(Note 13)*		
Redeemable noncontrolling interests	**1,180**	1,053
Equity		
Share capital		
Preference shares *(Note 8)*	**5,411**	5,141
Common shares (835 and 831 outstanding at March 31, 2014 and December 31, 2013, respectively)	**5,874**	5,744
Additional paid-in capital	**745**	746
Retained earnings	**2,505**	2,550
Accumulated other comprehensive loss *(Note 9)*	**(497)**	(599)
Reciprocal shareholding	**(86)**	(86)
Total Enbridge Inc. shareholders' equity	**13,952**	13,496
Noncontrolling interests	**4,066**	4,014
	18,018	17,510
	62,535	57,568

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

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

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

2. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

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

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

FUTURE ACCOUNTING POLICY CHANGES

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. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

3. SEGMENTED INFORMATION

Three months ended March 31, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**447**	**1,285**	**6,422**	**2,367**	**-**	**10,521**
Commodity and gas distribution costs	**-**	**(846)**	**(6,119)**	**(1,614)**	**-**	**(8,579)**
Operating and administrative	**(256)**	**(133)**	**(34)**	**(323)**	**1**	**(745)**
Depreciation and amortization	**(117)**	**(84)**	**(12)**	**(149)**	**(4)**	**(366)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(5)**	**-**	**(5)**
	74	**222**	**257**	**276**	**(3)**	**826**
Income from equity investments	**36**	**-**	**49**	**18**	**11**	**114**
Other income/(expense)	**1**	**3**	**5**	**(1)**	**(146)**	**(138)**
Interest income/(expense)	**(87)**	**(40)**	**(18)**	**(111)**	**18**	**(238)**
Income taxes recovery/(expense)	**21**	**(49)**	**(102)**	**(51)**	**64**	**(117)**
Earnings/(loss) from continuing operations	**45**	**136**	**191**	**131**	**(56)**	**447**
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)	**45**	**136**	**237**	**131**	**(56)**	**493**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**(47)**	**-**	**(48)**
Preference share dividends	**-**	**-**	**-**	**-**	**(55)**	**(55)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**44**	**136**	**237**	**84**	**(111)**	**390**
Additions to property, plant and equipment[2]	**1,498**	**97**	**118**	**682**	**14**	**2,409**

Three months ended March 31, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	544	1,066	4,523	1,764	-	7,897
Commodity and gas distribution costs	-	(666)	(4,448)	(1,164)	-	(6,278)
Operating and administrative	(238)	(134)	(41)	(260)	9	(664)
Depreciation and amortization	(100)	(79)	(15)	(124)	(4)	(322)
Environmental costs, net of recoveries	-	-	-	(183)	-	(183)
	206	187	19	33	5	450
Income from equity investments	25	-	33	13	30	101
Other income/(expense)	10	1	15	(3)	(71)	(48)
Interest expense	(71)	(40)	(18)	(93)	(33)	(255)
Income taxes recovery/(expense)	(22)	(41)	(20)	(12)	33	(62)
Earnings/(loss)	148	107	29	(62)	(36)	186
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	104	-	103
Preference share dividends	-	-	-	-	(39)	(39)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	147	107	29	42	(75)	250
Additions to property, plant and equipment[2]	767	102	138	445	5	1,457

1 *Included within the Corporate segment was Interest income of $155 million (2013 - $92 million) charged to other operating segments.*

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

The Company has downwardly revised both Commodity sales and Commodity costs by $120 million for the three months ended March 31, 2013 relating to a correction to intercompany transactions within the Gas Pipeline, Processing and Energy Services segment, as discussed in Note 4 to the consolidated financial statements for the year ended December 31, 2013. This presentation matter had no net effect on the margin, earnings or cash flows for the period.

TOTAL ASSETS

(millions of Canadian dollars)	**March 31, 2014**	December 31, 2013
Liquids Pipelines	**22,993**	20,950
Gas Distribution	**8,737**	7,942
Gas Pipelines, Processing and Energy Services	**7,593**	7,015
Sponsored Investments	**19,568**	18,527
Corporate	**3,644**	3,134
	62,535	57,568

4. DISCONTINUED OPERATIONS

Effective March 1, 2014, the Company completed the sale of certain of its Enbridge Offshore Pipelines assets located within the Stingray corridor to an unrelated third party for cash proceeds of $11 million (US$10 million), subject to working capital adjustments. The gain of $70 million (US$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of $59 million (US$53 million), is presented as Earnings from discontinued operations. The results of operations, including revenues of $37 million and related cash flows, have also been presented as discontinued operations for the three months ended March 31, 2014. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain Enbridge Energy Partners, L.P. (EEP) subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$433 million ($479 million) and US$380 million ($404 million) as at March 31, 2014 and December 31, 2013, respectively.

6. DEBT

During the three months ended March 31, 2014, the Company completed aggregate issuances of medium-term notes of $1,530 million which carry interest rates of 1.7% to 4.6% and have maturities ranging from three to 30 years, with the exception of $130 million that matures in 50 years. Subsequent to March 31, 2014, medium-term notes of $300 million with a three-year maturity were issued through the Company's subsidiary Enbridge Gas Distribution Inc. (EGD).

CREDIT FACILITIES

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

		March 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**156**	**144**	300
Gas Distribution[3]	2015-2019	**708**	**708**	**-**	713
Sponsored Investments	2015-2018	**4,949**	**1,242**	**3,707**	4,781
Corporate	2015-2018	**12,158**	**4,299**	**7,859**	11,805
		18,115	**6,405**	**11,710**	17,599
Southern Lights project financing[1]	2014-2015	**1,617**	**1,543**	**74**	1,570
Total committed credit facilities		**19,732**	**7,948**	**11,784**	19,169

1 *Total facilities inclusive of $65 million for debt service reserve letters of credit.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *A portion of the proceeds from the medium-term note issuance completed by EGD subsequent to March 31, 2014 were used to repay credit facility draws outstanding as at March 31, 2014.*

In addition to the committed credit facilities noted above, the Company also has $277 million of uncommitted demand credit facilities, of which $228 million was unutilized as at March 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 2014 to 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $5,489 million (December 31, 2013 - $4,580 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

7. OTHER LONG-TERM LIABILITIES

ASSET RETIREMENT OBLIGATIONS

During the three months ended March 31, 2014, the Company recognized asset retirement obligations (ARO) in the amount of $162 million. Of the amount, $66 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur in 2014 and $96 million related to the Canadian and United States portions of the Line 3 Replacement Program announced in March 2014.

The Company records ARO at fair value in the period in which they can be reasonably determined. Fair value is determined based on expected future cash flows and estimated retirement periods, as well as discount and inflation rates. ARO of $66 million were classified within Accounts payable and other and of $96 million were classified within Other long-term liabilities, with an offset to Property, plant and equipment on the Consolidated Statements of Financial Position.

8. SHARE CAPITAL

PREFERENCE SHARES

	March 31, 2014		December 31, 2013	
	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of preference shares in millions)				
Preference Shares, Series A	**5**	**125**	5	125
Preference Shares, Series B	**20**	**500**	20	500
Preference Shares, Series D	**18**	**450**	18	450
Preference Shares, Series F	**20**	**500**	20	500
Preference Shares, Series H	**14**	**350**	14	350
Preference Shares, Series J	**8**	**199**	8	199
Preference Shares, Series L	**16**	**411**	16	411
Preference Shares, Series N	**18**	**450**	18	450
Preference Shares, Series P	**16**	**400**	16	400
Preference Shares, Series R	**16**	**400**	16	400
Preference Shares, Series 1	**16**	**411**	16	411
Preference Shares, Series 3	**24**	**600**	24	600
Preference Shares, Series 5	**8**	**206**	8	206
Preference Shares, Series 7	**10**	**250**	10	250
Preference Shares, Series 9	**11**	**275**	-	-
Issuance costs		**(116)**		(111)
Balance at end of period		**5,411**		5,141

Characteristics of the preference shares are as follows:

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

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

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

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

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8) or 2.7% (Series 10)); 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 *A cash dividend of $0.2411 per share will be payable on June 1, 2014 to Series 9 shareholders. The regular quarterly dividend of $0.275 per share takes effect on September 1, 2014.*

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2013 - 18 million) for the three months ended March 31, 2014, resulting from the Company's reciprocal investment in Noverco Inc.

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

	Three months ended March 31,	
	2014	2013
(number of shares in millions)		
Weighted average shares outstanding	**820**	789
Effect of dilutive options	**10**	12
Diluted weighted average shares outstanding	**830**	801

For the three months ended March 31, 2014, 12,209,636 anti-dilutive stock options (2013 - 6,353,550) with a weighted average exercise price of $46.77 (2013 - $44.85) were excluded from the diluted earnings per common share calculation.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in Accumulated other comprehensive loss (AOCI) attributable to Enbridge common shareholders for the three months ended March 31, 2014 and 2013 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	**(1)**	**378**	**(778)**	**(15)**	**(183)**	**(599)**
Other comprehensive income/(loss) retained in AOCI	**(308)**	**(103)**	**368**	**4**	**-**	**(39)**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**37**	**-**	**-**	**-**	**-**	**37**
Commodity contracts[2]	**4**	**-**	**-**	**-**	**-**	**4**
Foreign exchange contracts[3]	**15**	**-**	**-**	**-**	**-**	**15**
Other contracts[4]	**(4)**	**-**	**-**	**-**	**-**	**(4)**
Amortization of pension and OPEB actuarial loss[5]	**-**	**-**	**-**	**-**	**3**	**3**
	(256)	**(103)**	**368**	**4**	**3**	**16**
Tax impact						
Income tax on amounts retained in AOCI	**79**	**14**	**-**	**-**	**-**	**93**
Income tax on amounts reclassified to earnings	**(5)**	**-**	**-**	**-**	**(2)**	**(7)**
	74	**14**	**-**	**-**	**(2)**	**86**
Balance at March 31, 2014	**(183)**	**289**	**(410)**	**(11)**	**(182)**	**(497)**

(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, 2013	(621)	474	(1,265)	(26)	(324)	(1,762)
Other comprehensive income/(loss) retained in AOCI	78	(28)	127	2	-	179
Other comprehensive gains reclassified to earnings						
Interest rate contracts[1]	43	-	-	-	-	43
Commodity contracts[2]	1	-	-	-	-	1
Amortization of pension and OPEB actuarial loss[5]	-	-	-	-	13	13
	122	(28)	127	2	13	236
Tax impact						
Income tax on amounts retained in AOCI	(20)	4	-	-	-	(16)
Income tax on amounts reclassified to earnings	(12)	-	-	-	(4)	(16)
	(32)	4	-	-	(4)	(32)
Balance at March 31, 2013	(531)	450	(1,138)	(24)	(315)	(1,558)

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 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.*

10. 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's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over a five year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues denominated in United States dollars.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 1.9%.

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 2017. A total of $9,543 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.6%.

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

Commodity Price Risk

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

Equity Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at March 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 in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

March 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						
Foreign exchange contracts	**31**	**9**	**36**	**76**	**(40)**	**36**
Interest rate contracts	**98**	**-**	**10**	**108**	**(12)**	**96**
Commodity contracts	**4**	**-**	**128**	**132**	**(67)**	**65**
Other contracts	**2**	**-**	**7**	**9**	**-**	**9**
	135	**9**	**181**	**325**	**(119)**	**206**
Deferred amounts and other assets						
Foreign exchange contracts	**16**	**28**	**7**	**51**	**(48)**	**3**
Interest rate contracts	**137**	**-**	**-**	**137**	**(42)**	**95**
Commodity contracts	**6**	**-**	**32**	**38**	**(13)**	**25**
Other contracts	**2**	**-**	**2**	**4**	**-**	**4**
	161	**28**	**41**	**230**	**(103)**	**127**
Accounts payable and other						
Foreign exchange contracts	**(1)**	**(35)**	**(132)**	**(168)**	**40**	**(128)**
Interest rate contracts	**(316)**	**-**	**(13)**	**(329)**	**21**	**(308)**
Commodity contracts	**(12)**	**-**	**(204)**	**(216)**	**67**	**(149)**
	(329)	**(35)**	**(349)**	**(713)**	**128**	**(585)**
Other long-term liabilities						
Foreign exchange contracts	**(1)**	**(41)**	**(757)**	**(799)**	**48**	**(751)**
Interest rate contracts	**(167)**	**-**	**-**	**(167)**	**33**	**(134)**
Commodity contracts	**(1)**	**-**	**(782)**	**(783)**	**13**	**(770)**
	(169)	**(41)**	**(1,539)**	**(1,749)**	**94**	**(1,655)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**45**	**(39)**	**(846)**	**(840)**	**-**	**(840)**
Interest rate contracts	**(248)**	**-**	**(3)**	**(251)**	**-**	**(251)**
Commodity contracts	**(3)**	**-**	**(826)**	**(829)**	**-**	**(829)**
Other contracts	**4**	**-**	**9**	**13**	**-**	**13**
	(202)	**(39)**	**(1,666)**	**(1,907)**	**-**	**(1,907)**

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

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

March 31, 2014	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**776**	**25**	**25**	**413**	**2**	**4**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,469**	**2,751**	**2,323**	**2,557**	**1,714**	**3,771**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**2**	**28**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**3,877**	**5,314**	**5,117**	**4,110**	**280**	**465**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,826**	**1,792**	**1,835**	**1,090**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**49**	**45**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(76)**	**(8)**	**(19)**	**(13)**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(22)**	**(30)**	**(23)**	**(18)**	**(9)**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(12)**	**(5)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**49**	**5**	**20**	**40**	**30**	**8**

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

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

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**29**	14
Interest rate contracts	**(242)**	79
Commodity contracts	**(7)**	-
Other contracts	**5**	2
Net investment hedges		
Foreign exchange contracts	**(48)**	(22)
	(263)	73
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*		
Foreign exchange contracts[1]	**(1)**	-
Interest rate contracts[2]	**21**	13
Commodity contracts[3]	**7**	-
Other contracts[4]	**(4)**	-
	23	13
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**25**	38
Commodity contracts[3]	**1**	(1)
	26	37

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

The Company estimates that $44 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 45 months at March 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.

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**(420)**	(193)
Interest rate contracts[2]	**1**	(4)
Commodity contracts[3]	**173**	(53)
Other contracts[4]	**5**	6
Total unrealized derivative fair value loss	**(241)**	(244)

1 Reported within Transportation and other services revenues (2014 - $231 million loss; 2013 - $91 million loss) and Other expense (2014 - $189 million loss; 2013 - $102 million loss) in the Consolidated Statements of Earnings.

2 Reported as an increase to Interest expense in the Consolidated Statements of Earnings.

3 Reported within Transportation and other services revenues (2014 - $134 million gain; 2013 - $32 million loss), Commodity costs (2014 - $40 million gain; 2013 - $17 million loss) and Operating and administrative expense (2014 - $1 million loss; 2013 - $4 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 at March 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. 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:

	March 31, 2014	December 31, 2013
(millions of Canadian dollars)		
Canadian financial institutions	**168**	230
United States financial institutions	**114**	227
European financial institutions	**120**	192
Other[1]	**103**	97
	505	746

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

As at March 31, 2014, the Company had provided letters of credit totalling $154 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held $10 million of cash collateral on derivative asset exposures at March 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 in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

Level 3

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

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

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

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

March 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**76**	**-**	**76**
Interest rate contracts	**-**	**108**	**-**	**108**
Commodity contracts	**2**	**41**	**89**	**132**
Other contracts	**-**	**9**	**-**	**9**
	2	**234**	**89**	**325**
Long-term derivative assets				
Foreign exchange contracts	**-**	**51**	**-**	**51**
Interest rate contracts	**-**	**137**	**-**	**137**
Commodity contracts	**-**	**16**	**22**	**38**
Other contracts	**-**	**4**	**-**	**4**
	-	**208**	**22**	**230**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(168)**	**-**	**(168)**
Interest rate contracts	**-**	**(329)**	**-**	**(329)**
Commodity contracts	**(5)**	**(121)**	**(90)**	**(216)**
	(5)	**(618)**	**(90)**	**(713)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(799)**	**-**	**(799)**
Interest rate contracts	**-**	**(167)**	**-**	**(167)**
Commodity contracts	**-**	**(629)**	**(154)**	**(783)**
	-	**(1,595)**	**(154)**	**(1,749)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(840)**	**-**	**(840)**
Interest rate contracts	**-**	**(251)**	**-**	**(251)**
Commodity contracts	**(3)**	**(693)**	**(133)**	**(829)**
Other contracts	**-**	**13**	**-**	**13**
	(3)	**(1,771)**	**(133)**	**(1,907)**

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:

March 31, 2014	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	6	Forward gas price	3.88	5.72	4.70	$/mmbtu[3]
Crude	3	Forward crude price	73.66	95.44	79.37	$/barrel
NGL	(3)	Forward NGL price	-	2.18	0.68	$/gallon
Power	(144)	Forward power price	40.50	76.00	58.27	$/MWH
Commodity contracts - physical[1]						
Natural gas	(15)	Forward gas price	3.34	5.73	4.42	$/mmbtu[3]
Crude	9	Forward crude price	79.38	125.17	98.11	$/barrel
NGL	4	Forward NGL price	0.01	2.81	1.57	$/gallon
Power	(1)	Forward power price	34.23	45.35	38.00	$/MWH
Commodity options[2]						
Natural gas	2	Option volatility	28%	77%	36%	
Crude	(1)	Option volatility	15%	19%	18%	
NGL	7	Option volatility	27%	40%	31%	
	(133)					

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:

	Three months ended March 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]	**12**	(36)
Included in OCI	**5**	1
Settlements	**14**	10
Level 3 net derivative liability at end of period	**(133)**	(49)

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 March 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 $88 million at March 31, 2014 (December 31, 2013 - $103 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $307 million at March 31, 2014 (December 31, 2013 - $287 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. At March 31, 2014, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2013 - $580 million).

At March 31, 2014, the Company's long-term debt had a carrying value of $27,725 million (December 31, 2013 - $25,168 million) and a fair value of $29,963 million (December 31, 2013 - $27,469 million).

11. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2014 was 20.7% (2013 - 25.0%). The period-over-period decrease in the effective tax rate is primarily attributable to the tax effect of higher United States income attributable to noncontrolling interests in the first quarter of 2014, mainly due to the absence of EEP's cost accrual recorded in the first quarter of 2013 associated with the Line 6B crude oil release.

12. RETIREMENT AND POSTRETIREMENT BENEFITS

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

NET BENEFIT COSTS RECOGNIZED

	Three months ended March 31,	
	2014	2013
(millions of Canadian dollars)		
Benefits earned during the period	**30**	28
Interest cost on projected benefit obligations	**26**	22
Expected return on plan assets	**(32)**	(26)
Amortization of prior service costs	**-**	1
Amortization of actuarial loss	**7**	13
Net benefit costs on an accrual basis[1,2]	**31**	38

1 *Included in net benefit costs for the three months ended March 31, 2014 are costs related to OPEB of $4 million (2013 - $4 million).*

2 *For the three months ended March 31, 2014, offsetting regulatory liability of $2 million (2013 - $1 million regulatory asset) has been recorded to the extent pension and OPEB costs are expected to be refunded to or collected from customers in future rates.*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Three months ended March 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Contributions paid	**32**	18	**2**	3
Contributions expected to be paid in the next nine months	**96**		**9**	
Total contributions expected to be paid in the year	**128**		**11**	

13. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 20.6% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. As at March 31, 2014, EEP's total cost estimate for the Line 6B crude oil release remained at US$1,122 million ($181 million after-tax attributable to Enbridge). This total estimate is before insurance recoveries and excludes fines and penalties other than the US$30 million discussed below. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta. EEP is in the process of working with the EPA to ensure this work is completed as soon as reasonably possible considering weather conditions.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at March 31, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Including EEP's remediation spending through March 31, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at March 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 which are effective May 1, 2014 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 will increase to US$30 million per event, from the current US$10 million. In the unlikely event multiple insurable incidents occur which exceed coverage limits 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 25 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.

As at March 31, 2014, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by Pipeline and Hazardous Materials Safety Administration that EEP paid during the third quarter of 2012. The total also included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, 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. Discussions with governmental agencies regarding fines and penalties are ongoing.

TAX MATTERS

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

OTHER LITIGATION

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

HIGHLIGHTS

	Three months ended March 31, 2014	2013
(unaudited; millions of Canadian dollars, except per share amounts)		
Earnings attributable to common shareholders		
Liquids Pipelines	**44**	147
Gas Distribution	**136**	107
Gas Pipelines, Processing and Energy Services	**191**	29
Sponsored Investments	**84**	42
Corporate	**(111)**	(75)
Earnings attributable to common shareholders from continuing operations	**344**	250
Discontinued operations - Gas Pipelines, Processing and Energy Services	**46**	-
	390	250
Earnings per common share	**0.48**	0.32
Diluted earnings per common share	**0.47**	0.31
Adjusted earnings[1]		
Liquids Pipelines	**218**	219
Gas Distribution	**103**	113
Gas Pipelines, Processing and Energy Services	**59**	59
Sponsored Investments	**84**	67
Corporate	**28**	30
	492	488
Adjusted earnings per common share	**0.60**	0.62
Cash flow data		
Cash provided by operating activities	**333**	793
Cash used in investing activities	**(2,743)**	(1,643)
Cash provided by financing activities	**2,465**	420
Dividends		
Common share dividends declared	**291**	254
Dividends paid per common share	**0.3500**	0.3150
Shares outstanding *(millions)*		
Weighted average common shares outstanding	**820**	789
Diluted weighted average common shares outstanding	**830**	801
Operating data		
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*		
Canadian Mainline[2]	**1,904**	1,783
Regional Oil Sands System[3]	**671**	462
Spearhead Pipeline	**184**	165
Gas Distribution - Enbridge Gas Distribution (EGD)		
Volumes *(billions of cubic feet)*	**212**	181
Number of active customers *(thousands)*[4]	**2,076**	2,042
Heating degree days[5]		
Actual	**2,206**	1,798
Forecast based on normal weather	**1,777**	1,871
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*		
Alliance Pipeline US	**1,728**	1,632
Vector Pipeline	**1,783**	1,720
Enbridge Offshore Pipelines	**1,371**	1,452

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

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

3 *Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*
4 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*
5 *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.*

SHAREHOLDER INFORMATION

Registrar and Transfer Agent in Canada

Inquiries regarding the Dividend Reinvestment and Share Purchase Plan, change of address, share transfer, lost certificates, dividends, and duplicate mailings should be directed to:

CST Trust Company
P.O. Box 700
Station B
Montreal, Quebec H3B 3K3
Toll free: (800) 387-0825

Dividend Reinvestment & Share Purchase Plan

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in common shares, or to make payments to purchase additional shares in, either case free of brokerage or other charges. Share purchase cut-off for the 2014 second quarter optional cash payment to purchase additional shares is May 26, 2014.

Investor Relations

Shareholder inquiries regarding the Company's financial and operating performance should be directed to:

Investor Relations
Enbridge Inc.
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Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804
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May 7, 2014

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