Third Quarter

INTERIM REPORT
TO SHAREHOLDERS
For the nine months ended

SEPTEMBER 30, 2013

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- Third quarter earnings were $421 million and nine month earnings were $713 million, including the impact of net unrealized non-cash mark-to-market gains and losses
- Nine month adjusted earnings per share increased 12% to $1.33 per common share; three month adjusted earnings per common share remained at $0.34
- Enbridge announced it is proceeding with the Woodland Pipeline Extension Project; Enbridge's share of the investment is expected to be approximately $0.6 billion
- Enbridge announced it will construct facilities and provide transportation services to the JACOS Hangingstone Oil Sands Project for an approximate investment of $0.1 billion
- Enbridge secured commercial support for the $1.6 billion Wood Buffalo Extension Pipeline from Cheecham to Hardisty, Alberta
- Enbridge secured commercial support for its $1.4 billion Norlite Pipeline System, a diluent pipeline system serving the Athabasca oil sands region
- Enbridge secured a 50% interest in the 80-megawatt Saint Robert Bellarmin Wind Project, with an approximate investment of $0.1 billion
- Enbridge continued to execute funding for its record $36 billion growth plan with year-to-date issuances of medium-term notes of approximately $2.4 billion, cumulative redeemable preference shares of approximately $1.2 billion, common shares of approximately $600 million plus another $248 million of proceeds from Enbridge's 38.9% interest in Noverco's sale of a portion of Enbridge shares through a secondary offering, as well as increased its enterprise-wide general purpose credit facilities to approximately $16 billion

CALGARY, ALBERTA, November 6, 2013 – Enbridge Inc. (TSX:ENB) (NYSE:ENB) – "Enbridge continued its strong performance in 2013," said Al Monaco, President and Chief Executive Officer of Enbridge Inc. (Enbridge or the Company). "Our value proposition remains the same; a unique combination of superior growth, a reliable business model and strong, predictable dividend increases for shareholders. During the third quarter, we continued to add to our record slate of commercially secured growth projects and advanced on a number of other potential opportunities currently under development. In total, 14 new projects have come into service to date in 2013. We remain on track to achieve full year adjusted earnings per share well within our guidance range of $1.74 to $1.90 per share.

"Today's North American energy fundamentals combined with the strategic positioning of our assets are driving significant investment opportunities for Enbridge both in the short and long term," said Mr. Monaco. "In the third quarter, our Board of Directors approved our five-year strategic plan, which we expect will generate significant shareholder value through growth of 10% to 12% in average annual adjusted earnings per share and dividends over the next five years. The strategic position of our assets, our inventory of projects in development and new growth platforms also position us to maintain industry leading growth beyond 2017. That said, our number one priority will continue to be a focus on the safety and reliability of our systems."

Operations

Within Liquids Pipelines, nine month earnings growth was driven by throughput increases over the prior year, primarily from strong first quarter volume growth on Canadian Mainline due to strong supply from western Canada and the on-going effect of crude oil price differentials which drove an increase in long-haul barrels on the Enbridge system. However, volume growth was somewhat tempered in the second and third quarters of 2013 due to the effects of United States midwest refinery turnarounds and shutdowns. Additionally, both the second and third quarters of 2013 reflected lower Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Tolls than the corresponding 2012 periods, which partially offset the volume increase. Regional Oil Sands System contributed to higher earnings from the benefits of new infrastructure including the Woodland and Wood Buffalo pipelines. Also providing a year-to-date increase in adjusted earnings was Enbridge's 50% interest in the Seaway Crude Pipeline System (Seaway Pipeline).

Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) continued to benefit from customer growth as well as from the absence of earnings sharing in 2013. Partially offsetting the favourable impacts were higher operating and administrative costs. The EGD loss in the third quarter of 2013 primarily reflects the inherent seasonality in EGD's operations where the majority of earnings are achieved in the colder months of the year.

Energy Services had a third consecutive quarter of earnings growth, compared with the corresponding 2012 period, as wide location and crude grade differentials continued to provide attractive arbitrage opportunities. However, the rate of adjusted earnings growth in the third quarter of 2013 was tempered compared with the first half of the year due to narrowing differentials, as expected.

Within Sponsored Investments, Enbridge Energy Partners, L.P. (EEP) earnings increased due to Enbridge's May 2013 investment in preferred units of EEP and higher general partner incentive distributions. However, low natural gas and natural gas liquids (NGL) commodity prices as well as lower volumes continued to impact earnings in EEP's natural gas gathering and processing business. Enbridge Income Fund (the Fund) continued to deliver strong results, bolstered by the renewable energy and crude oil storage assets dropped down to the Fund in 2012 as well as the Bakken Expansion Program which commenced operations in March 2013.

Finally, as the Company continued to pre-fund its record slate of commercially secured growth projects, financing costs have increased primarily through increased preference share dividends in the Company's Corporate segment.

Adjusted earnings for the third quarter of 2013 excluded, among other items, a further accrual of $13 million after-tax and before insurance recoveries recognized in the third quarter of 2013 in connection with the June 2013 Line 37 crude oil release, bringing the total estimated costs associated with this incident to $53 million after-tax. Finally, the Company's earnings continued to reflect changes in unrealized mark-to-market accounting impacts related to the comprehensive long-term economic hedging program Enbridge has in place to mitigate exposures to interest rate variability and foreign exchange, as well as commodity prices. The Company believes that the hedging program supports the generation of reliable cash flows and dividend growth.

Key Developments

"We continue to position Enbridge to meet the growing demand for new energy infrastructure across the North American energy industry and currently have $29 billion of enterprise-wide commercially secured projects expected to come into service between 2013 and 2017," said Mr. Monaco. "Enbridge's existing infrastructure, combined with our ability to safely and successfully execute new projects, will allow us to expand our system and capitalize on growth opportunities well into the second half of the decade."

During the third quarter of 2013, Enbridge announced investments in approximately $4 billion of oil sands infrastructure projects which are expected to be in-service at various points between 2015 and 2017. The projects include the proposed $1.4 billion Norlite Pipeline which will be capable of transporting 270,000 bpd of diluent from Edmonton into the oil sands region as well as the $1.6 billion Wood Buffalo pipeline extension which will be an extension of the recently commissioned Wood Buffalo pipeline. The Wood Buffalo pipeline extension will transport as much as 490,000 bpd of diluted bitumen for the proposed Fort Hills oil sands project (Fort Hills Project) and Suncor Energy Oil Sands Limited Partnership's (Suncor Partnership) oil sands production in the Athabasca region to Enbridge's mainline hub at Hardisty.

"Our strategic position and scale in the Alberta oil sands continues to present great growth opportunities for Enbridge," said Mr. Monaco. "The projects we have recently announced will add significant incremental capacity from the region, allowing us to provide cost-effective transportation solutions for producers."

Enbridge continued to expand its renewable energy generation capacity in the third quarter of 2013. In July, the Company secured a 50% interest in the 80-megawatt (MW) Saint Robert Bellarmin Wind Project (Saint Robert) in Quebec for an approximate investment of $0.1 billion. Additionally, in August the Company commissioned Phase 2 of the 300-MW Lac Alfred Wind Project (Lac Alfred), also located in Quebec. Both Saint Robert and Lac Alfred deliver energy to Hydro Quebec under long-term power purchase agreements (PPA). The third quarter of 2013 also included the commissioning of Enbridge's first power transmission project, the 300-MW Montana-Alberta Tie-Line.

"Renewable energy is a growing part of our business," said Mr. Monaco. "We are the number one producer of solar energy in Canada, the second largest producer of wind power and currently have an interest in over 1,700 MW of renewable power generation capacity. Projects like Saint Robert and Lac Alfred align with Enbridge's value proposition and are an important part of our strategy to develop new platforms to diversify and sustain long-term growth."

Enbridge remained active in the capital markets in the third quarter, issuing approximately $2.4 billion of medium-term notes and US$200 million of preference shares. Additionally, the Company further bolstered its entity-wide general purpose credit facilities by an additional $1.3 billion. This financing will be primarily used to fund the Company's record slate of attractive growth projects.

In October, Midcoast Energy Partners, L.P. (MEP), currently a wholly-owned subsidiary of EEP, announced its initial public offering of 18.5 million Class A common units. The master limited partnership's initial asset will consist of an approximate 40% ownership interest in EEP's existing natural gas and NGL midstream business.

"The offering will provide EEP another source of capital funding, lower its cost of capital and enhance the strategic focus of its operations," Mr. Monaco said. "Under the new structure, EEP will focus on its crude oil liquids pipeline business and MEP will focus on its natural gas and NGL midstream business."

In September 2013, Enbridge was once again named to the Dow Jones Sustainability Indices for the World and North America. Enbridge was also named by the Carbon Disclosure Project (CDP) to their list of Global 500 companies who demonstrate leadership in addressing the challenges of climate change and greenhouse gas disclosure and management. In October, Enbridge was recognized for the twelfth consecutive year as one of Canada's Top 100 Employers.

"External recognition confirms that we are achieving our objectives not only with respect to the long-term financial outlook for the Company, but also in our environmental and social performance," said Mr. Monaco. "Enbridge has long been committed to an approach that reflects our core values of integrity, safety and respect and to ensuring that our decisions have the best possible impact on our stakeholders, the environment and the communities in which we live and work."

THIRD QUARTER 2013 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. We further draw your attention to Note 2, Revision of Prior Period Financial Statements to the Consolidated Financial Statements as at and for the three and nine months ended September 30, 2013, which discusses a non-cash revision to comparative financial statements. The discussion and analysis included in this news release is based on revised financial results for the three and nine months ended September 30, 2012.

- Earnings attributable to common shareholders increased from $187 million in the third quarter of 2012 to $421 million in the third quarter of 2013. The comparability of the Company's results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains or losses. Also impacting the comparability of earnings for the three months ended September 30, 2013 were certain out-of-period adjustments recognized in the third quarter of 2013, including a non-cash adjustment of $37 million after-tax, to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts within Regional Oil Sands System. The Regional Oil Sands System also included an out-of-period adjustment of $31 million after-tax related to the recovery of income taxes under a long-term contract, partially offset by a related correction to deferred income tax expense. In Gas Distribution, the Company recognized an out-of-year adjustment of $56 million after-tax reflecting an increase to gas transportation costs which had incorrectly been deferred. In the third quarter of 2013, the Company also increased its accrual for remediation work in relation to the June 2013 Line 37 crude oil release by approximately $13 million after-tax and before insurance recoveries.

- Enbridge's adjusted earnings for the third quarter of 2013 increased to $278 million from $267 million in the comparative period of 2012. The adjusted earnings increase was primarily driven by higher contributions within Sponsored Investments. The contribution to adjusted earnings from EEP increased due to distributions received from Enbridge's May 2013 investment in preferred units in EEP and higher incentive distributions, partially offset by lower volumes and weak commodity price environment in EEP's gas gathering and processing business. Contributions from crude oil storage and renewable energy assets, acquired by the Fund in 2012 from Enbridge, also drove higher adjusted earnings within Sponsored Investments. Energy Services contributed to higher earnings as wide location and crude grade differentials provided attractive arbitrage opportunities. Adjusted earnings for Liquids Pipelines were comparable to the corresponding 2012 period, although due to offsetting factors. Providing positive earnings growth in Liquids Pipelines were higher contracted volumes and new assets placed into service in 2012 on Regional Oil Sands System and higher volumes on both Canadian Mainline and Seaway Pipeline. These favourable factors were offset by a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll and higher operating and financing costs. Finally, within Enbridge's Corporate segment, increased preference share dividends related to preference share issuances completed to pre-fund the Company's commercially secured growth projects decreased adjusted earnings compared with the third quarter of 2012.

- On October 30, 2013, Enbridge announced that it was selected by Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), as well as the 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 pipeline will be an extension of Enbridge's existing Wood Buffalo Pipeline and will include the 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' 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.

- On October 30, 2013, Enbridge announced it will develop the Norlite Pipeline System, a new industry diluent pipeline to meet the needs of multiple producers in the Athabasca oil sands region. Subject to finalization of scope, the 16-inch diameter base scope of the project will be anchored by throughput commitments from both the Fort Hills Partners for volumes for the proposed Fort Hills Project and the Suncor Partnership's proprietary oil sands production. If Enbridge is successful in securing additional long term commitments on the proposed Norlite Pipeline System, the scope of the project could be increased to a 20-inch to 24-inch diameter pipeline system. The proposed Norlite Pipeline System will involve the construction of a new 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, as well as a potential new lateral pipeline to Enbridge's Norealis Terminal that is currently under construction. The Norlite Pipeline System 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. Subject to regulatory approvals, the Norlite Pipeline System is expected to be completed in 2017 at an estimated cost of approximately $1.4 billion, and will provide capacity of 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 by the addition of pump stations.

- On September 26, 2013, Enbridge announced it will construct 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 finalization of definitive agreements and regulatory approvals, 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. Subject to finalization of scope, which could include an optional 8-inch diluent line to transport diluent to the JACOS Hangingstone project site, 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 early 2016.

- On July 25, 2013, Enbridge announced that it had received shipper sanctioning for the Woodland Pipeline Extension Project. The joint venture 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. Subject to finalization of scope and a definitive cost estimate, the project has a target in-service date of 2015.

- On July 22, 2013, Enbridge announced it had reached an agreement with EDF Energy Nouvelles Canada Development Inc. to acquire a 50% interest in the 80-MW Saint Robert wind project, located 300 kilometres (185 miles) east of Montreal, Quebec. The project is operational and power output is being delivered to Hydro-Quebec under a 20-year PPA. The Company's total investment in the project is approximately $0.1 billion.

- Since the end of the second quarter, the Company completed the following financing transactions:
  - On October 2, 2013, Enbridge issued medium-term notes of US$800 million with a 10-year maturity and US$350 million with a 3-year maturity.
  - On September 27, 2013, Enbridge completed an offering of eight million Cumulative Redeemable Preference Shares, Series 5 for gross proceeds of US$200 million.
  - On September 24, 2013, Enbridge Energy Management, L.L.C. (EEM) completed the issuance of 8.4 million Listed Shares for net proceeds of approximately US$236 million. EEM subsequently used the net proceeds from the offering to invest in an equal number of i-units of EEP.
  - On August 13, 2013, Enbridge issued medium-term notes of $250 million with a 10-year maturity and $300 million with a 30-year maturity, respectively, through its subsidiary Enbridge Pipelines Inc.

- On July 3, 2013, Enbridge issued medium-term notes of $450 million with a 10-year maturity and $250 million with a 29-year maturity.
- In the third quarter of 2013, Enbridge increased its enterprise-wide general purpose credit facilities to $16 billion.

DIVIDEND DECLARATION

On October 30, 2013, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2013 to shareholders of record on November 15, 2013.

Common Shares	$0.31500
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[1]	US$0.19590

1 This first dividend declared for the Preference Shares, Series 5 includes accrued dividends from September 27, 2013, the date the shares were issued. The regular quarterly dividend of US$0.275 per share will take effect on March 1, 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013

This Management's Discussion and Analysis (MD&A) dated November 5, 2013 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 and nine months ended September 30, 2013, 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 Financial Report for the year ended December 31, 2012. 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.

In connection with the preparation of the Company's first quarter consolidated financial statements, an error was identified in the manner in which the Company historically recorded deferred regulatory assets associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls for certain of its regulated operations. The error was not material to any of the Company's previously issued consolidated financial statements; however, as discussed in Note 2, Revision of Prior Period Financial Statements, to the consolidated financial statements as at and for the three and nine months ended September 30, 2013, prior year comparative financial statements have been revised to correct the effect of this error. This non-cash revision did not impact cash flows for any prior period. The discussion and analysis included herein is based on revised financial results for the three and nine months ended September 30, 2012 or other comparative periods as indicated.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**301**	276	**381**	567
Gas Distribution	**(85)**	(18)	**49**	80
Gas Pipelines, Processing and Energy Services	**68**	(191)	**257**	(409)
Sponsored Investments	**75**	80	**189**	211
Corporate	**62**	40	**(163)**	7
Earnings attributable to common shareholders	**421**	187	**713**	456
Earnings per common share	**0.52**	0.24	**0.89**	0.59
Diluted earnings per common share	**0.51**	0.24	**0.88**	0.59

Earnings attributable to common shareholders were $421 million for the three months ended September 30, 2013, or $0.52 per common share, compared with $187 million, or $0.24 per common share, for the three months ended September 30, 2012. Excluding the impacts of the unusual, non-recurring or non-operating factors, the Company continued to deliver steady growth across the majority of its business segments in 2013, as discussed in *Adjusted Earnings*.

The comparability of the Company's results is impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains or losses. The Company has a comprehensive long-term economic hedging program to mitigate exposures to 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. Additionally, impacting the comparability of earnings for the three months ended September 30, 2013 were certain out-of-period adjustments recognized in the third quarter of 2013, including a non-cash adjustment of $37 million after-tax, to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts within Regional Oil Sands System. Regional Oil Sands System also had an out-of-period adjustment of $31 million after-tax, related to the recovery of income taxes under a long-term contract, partially offset by a related correction to deferred income tax expense. In Gas Distribution, the Company recognized an out-of-year adjustment of $56 million after-tax reflecting an increase to gas transportation costs which had incorrectly been deferred.

Also impacting the third quarter of 2013 was an increased accrual of approximately $13 million after-tax and before insurance recoveries related to the June 2013 Line 37 crude oil release. Refer to *Recent Developments – Liquids Pipelines – Line 37 Crude Oil Release.* The Company's earnings for the three months ended September 30, 2013 also included an accrual of US$22 million ($5 million after-tax attributable to Enbridge) related to civil penalties expected to be paid by Enbridge Energy Partners, L.P. (EEP) under the Clean Water Act of the United States in respect of the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Crude Oil Releases.*

Earnings attributable to common shareholders were $713 million for the nine months ended September 30, 2013, or $0.89 per common share, compared with $456 million, or $0.59 per common share, for the nine months ended September 30, 2012. In addition to the trends experienced for the three month period discussed above, earnings for the nine months ended September 30, 2013 reflected costs of approximately $53 million after-tax and before insurance recoveries related to the Line 37 crude oil release. Also reducing earnings was an increased accrual of US$237 million ($35 million after-tax attributable to Enbridge) relating to the Line 6B crude oil release. In the second quarter of 2013, EEP recognized US$42 million ($6 million after-tax attributable to Enbridge) of insurance recoveries as a reduction to Environmental costs for the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Crude Oil Releases.*

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 green energy; prices of crude oil, natural gas, NGL and green 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 green 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, 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, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**187**	187	**565**	478
Gas Distribution	**(29)**	(18)	**109**	113
Gas Pipelines, Processing and Energy Services	**54**	46	**186**	134
Sponsored Investments	**86**	69	**224**	196
Corporate	**(20)**	(17)	**(12)**	(7)
Adjusted earnings	**278**	267	**1,072**	914
Adjusted earnings per common share	**0.34**	0.34	**1.33**	1.19

Adjusted earnings were $278 million, or $0.34 per common share, for the three months ended September 30, 2013 compared with $267 million, or $0.34 per common share, for the three months ended September 30, 2012. Adjusted earnings were $1,072 million, or $1.33 per common share, for the nine months ended September 30, 2013 compared with $914 million, or $1.19 per common share, for the nine months ended September 30, 2012. The following factors impacted adjusted earnings:

- Within Liquids Pipelines, Canadian Mainline adjusted earnings reflected strong throughput compared with the prior year, primarily due to strong supply from western Canada and the on-going effect of crude oil price differentials whereby demand for discounted crude by United States midwest refiners remained high and drove an increase in long-haul barrels on the Enbridge system, though limited by United States midwest refinery shutdowns. Partially offsetting the increased throughput was a lower quarter-over-quarter Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll which resulted in lower adjusted earnings in both the second and third quarters of 2013, respectively.

- Additionally within Liquids Pipelines, higher adjusted earnings were achieved on Regional Oil Sands System from higher contracted volumes and new assets placed into service in late 2012. Enbridge's 50% interest in the Seaway Crude Pipeline System (Seaway Pipeline) also contributed to higher adjusted earnings.
- Within Gas Distribution, Enbridge Gas Distribution Inc.'s (EGD) adjusted earnings were positively impacted by customer growth, lower depreciation and amortization expense and the absence of earnings sharing in 2013 compared with the corresponding period of 2012. Partially offsetting the increase in adjusted earnings were higher operating and administrative costs, including employee related costs and operational and safety costs. The negative contribution in the third quarter is indicative of the inherent seasonality in EGD's operations where the majority of earnings are achieved in the colder months of the year.
- Within Gas Pipelines, Processing and Energy Services, adjusted earnings increased due to wide location and crude grade differentials which gave rise to additional and more profitable margin opportunities in Energy Services. The increase in adjusted earnings was lower in the third quarter of 2013 compared with the first half of the year as the margins generated by Energy Services are dependent on market conditions which were less favourable in the third quarter.
- Within Sponsored Investments, EEP's contribution to adjusted earnings increased due to distributions received from Enbridge's May 2013 investment in preferred units of EEP and higher incentive distributions, partially offset by lower volumes and weak natural gas and NGL prices in EEP's gas gathering and processing business. In EEP's liquids business, higher tolls on EEP's major liquids pipeline assets were offset by lower volumes on the North Dakota system due to wide crude oil price differentials that made transportation by rail competitive, although tightening crude oil price differentials in the third quarter of 2013 resulted in incremental volumes returning to the North Dakota system. Furthermore, EEP's liquids business reflected costs associated with hydrostatic testing completed on Line 14 of EEP's Lakehead System. Adjusted earnings were also impacted by higher operating and administrative expense, primarily from an increased workforce, and higher depreciation expense associated with new assets placed into service.
- Additionally within Sponsored Investments, earnings from Enbridge Income Fund (the Fund) increased due to contributions from crude oil storage and renewable energy assets acquired from Enbridge and its wholly-owned subsidiaries in December 2012. The earnings from these acquired assets were previously presented in Liquids Pipelines and Gas Pipelines, Processing and Energy Services. Also positively impacting adjusted earnings were higher preferred unit distributions received from the Fund as well as earnings from the Bakken Expansion Program which commenced operations in March 2013. Partially offsetting the sources of growth in earnings was a one-time write-off of a regulatory deferral balance recognized in the first quarter of 2013. Refer to *Recent Developments – Sponsored Investments – Enbridge Income Fund – Saskatchewan System Shipper Complaint*.
- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings for the first nine months of 2013 increased compared with the corresponding period of 2012 due to stronger first quarter volumes and contributions from a power investment acquired in mid-2012. The negative contribution for the third quarter reflected the seasonality of the quarterly earnings profile.
- Also within the Corporate segment, a larger loss was recognized due to higher preference share dividends related to preference share issuances completed to pre-fund commercially secured growth projects, partially offset by lower net Corporate segment finance costs and lower operating and administrative costs.

RECENT DEVELOPMENTS

LIQUIDS PIPELINES

Line 37 Crude Oil Release

On June 22, 2013, Enbridge reported a release of light synthetic crude oil on its Line 37 pipeline approximately two kilometres north of Enbridge's Cheecham Terminal, which is located approximately 70 kilometres (45 miles) southeast of Fort McMurray, Alberta. Line 37 is part of Regional Oil Sands System and connects facilities in the Long Lake area to the Cheecham Terminal. The Company estimated the volume of the release at approximately 1,300 barrels, caused by unusually high water levels in the region which triggered ground movement on the right-of-way. The oil released from Line 37 has been recovered and on July 11, 2013 Line 37 returned to service at reduced operating pressure. Normal operating pressure was restored on Line 37 on July 29, 2013 after finalization of geotechnical analysis. Industry and environmental regulators have been to the site of the release and the Company has been providing regular updates on status of the clean-up, repair and remediation.

As a precaution, on June 22, 2013 the Company shut down the pipelines that share a corridor with Line 37, including the Athabasca, Waupisoo, Wood Buffalo and Woodland pipelines. The southern segment of the Athabasca pipeline was returned to service at normal pressure on June 23, 2013, with the northern segment resuming service on June 30, 2013 at reduced operating pressure following completion of extensive engineering and geotechnical analysis. Full service on the northern segment of the Athabasca pipeline was restored on July 11, 2013. The Waupisoo pipeline between Cheecham and Edmonton restarted on June 25, 2013 at normal operating pressure. The Wood Buffalo pipeline was restarted on July 2, 2013 at reduced pressure pending completion of further geotechnical analysis in the incident area and, on July 19, 2013, the Wood Buffalo pipeline was returned to normal operating pressure. The Woodland pipeline had been in the process of linefill at the time of the shutdown; linefill activities were completed in the third quarter of 2013.

The costs expected to be incurred in connection with this incident are approximately $53 million after-tax and before insurance recoveries, which is an increase of $13 million after-tax compared with the June 30, 2013 estimate. The additional accrual related to further excavation activities on the affected pipelines. Included in the cost are expenditures of approximately $15 million after-tax incurred to ensure integrity and long-term stability of Line 37 and other lines within the right-of-way. Lost revenue associated with the shutdown of Line 37 and the pipelines sharing a corridor with Line 37 was minimal. Enbridge carries liability insurance for sudden and accidental pollution events and expects to be reimbursed for its covered costs, subject to a $10 million deductible. The integrity and stability costs associated with remediating the impact of the high water levels are precautionary in nature and not covered by insurance. Enbridge expects to record receivables for amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery to be probable. Federal and provincial governmental agencies have initiated investigations into the Line 37 crude oil release and costs estimates exclude any potential fines or penalties.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Intercompany Accounts Receivable Sale

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

Midcoast Energy Partners Initial Public Offering

In May 2013, EEP formed Midcoast Energy Partners, L.P. (MEP), which is currently EEP's wholly-owned subsidiary. On June 14, 2013, MEP filed a Registration Statement on Form S-1 with the Securities and

Exchange Commission (SEC) related to MEP's proposed initial public offering of common units representing limited partner interests in MEP. On October 31, 2013, MEP launched its initial public offering of 18.5 million Class A common units representing limited partner interests pursuant to the Registration Statement on Form S-1. MEP will grant the underwriters a 30-day option to purchase from MEP up to an additional 2.8 million Class A common units at the initial public offering price. The Class A common units being offered represent a 40% limited partner interest in MEP, or a 46% limited partner interest if the underwriters exercise, in full, their option to purchase additional Class A common units. EEP, through certain of its subsidiaries, will hold a 2% general partner interest and the remaining limited partner interest in MEP. When the proposed offering closes, MEP's initial asset will consist of an approximate 40% ownership interest in EEP's existing natural gas and NGL midstream business. EEP will retain ownership of the general partner and all the incentive distribution rights in MEP.

Enbridge Energy Management, L.L.C. Share Issuance

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

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

EEP Preferred Unit Private Placement and Joint Funding Option Exercise

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

Lakehead System Crude Oil Releases

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 of 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 September 30, 2013, EEP's total cost estimate for the Line 6B crude oil release was US$1,035 million ($167 million after-tax attributable to Enbridge) which is an increase of US$215 million ($30 million after-tax attributable to Enbridge) compared with the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the Pipeline and Hazardous Materials Safety Administration (PHMSA) civil penalty of US$3.7 million which was paid in the third quarter of 2012. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) (the Order) 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. 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. The Order states the work must be completed by December 31, 2013.

The US$175 million increase in the total cost estimate during the three month period ended March 31, 2013 was attributable to additional work required by the Order. The US$40 million increase during the three month period ended June 30, 2013 was attributable to further refinement and definition of the additional dredging scope per the Order and all associated environmental, permitting, waste removal and other related costs. The actual costs incurred may differ from the foregoing estimate as EEP completes the work plan with the EPA related to the Order and works with other regulatory agencies to assure its work plan complies with their requirements. Any such incremental costs will not be recovered under EEP's insurance policies as the costs for the incident at September 30, 2013 exceeded the limits of its insurance coverage.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2013. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois on September 9, 2010, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release remains at US$48 million ($7 million after-tax attributable to Enbridge).

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 such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

The claims for 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. Based on EEP's remediation spending through September 30, 2013, 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. During the third quarter of 2013, EEP received US$42 million ($6 million after-tax attributable to Enbridge) of insurance recoveries for a claim filed in connection with the Line 6B crude oil release previously recognized as a reduction to environmental costs in the second quarter of 2013. EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) of insurance recoveries as reductions to environmental costs for the three and nine months ended September 30, 2012 for the Line 6B crude oil release. As at September 30, 2013, EEP has recorded total insurance recoveries of US$547 million for the Line 6B crude oil release, out of the US$650 million aggregate limit. EEP expects to record receivables for additional amounts claimed for recovery pursuant to its insurance policies during the period that EEP deems realization of the claim for recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of the remaining US$145 million coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP's claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery payment of US$42 million from the other remaining insurers and has since amended its lawsuit, such that it now includes only one insurer. While EEP believes the claims for the remaining US$103 million are covered under the policy, there can be no assurance that EEP will prevail in this lawsuit.

Effective May 1, 2013, Enbridge renewed its comprehensive property and liability insurance programs, under which EEP is insured through April 30, 2014, with a current liability aggregate limit of US$685 million, including sudden and accidental pollution liability. 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 the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 30 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, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a Notice of Probable Violation related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. One claim related to the Line 6A crude oil release has been filed against one of EEP’s affiliates by the State of Illinois in an Illinois state court. The parties are currently operating under an agreed interim order.

EEP expects that it will be required to pay civil penalties under the Clean Water Act of the United States in respect of the Line 6B crude oil release. As a result of recent communications from responsible governmental agencies, EEP expects to accrue US$22 million in the fourth quarter of 2013 in respect of these matters. 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, US$22 million represents the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed or required by 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 preliminary and ongoing.

As this matter represents a subsequent event to Enbridge, costs of $5 million after-tax attributable to Enbridge have been recognized as Environmental costs for the three and nine months ended September 30, 2013. The amount of any final fine and penalty or cost of injunctive relief may differ materially from the amount accrued as at September 30, 2013.

SPONSORED INVESTMENTS – ENBRIDGE INCOME FUND

Saskatchewan System Shipper Complaint

Throughout 2011 and 2012, the Fund continued to review the structure of its tolls with shippers following a shipper complaint in early 2011. On April 1, 2013, the Fund announced a settlement (the Settlement) had been concluded relating to new tolls on the Westspur System with a group of shippers. At the request of certain shippers who did not execute the Settlement, the National Energy Board (NEB) has not removed the interim status from the historical tolls and has made the new tolls interim as well. As at November 5, 2013, the Fund continues to work with shippers to resolve the matter.

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

CORPORATE

Noverco

Enbridge owns an equity interest in Noverco through a 38.9% common share holding and an investment in preferred shares. In turn, Noverco holds, directly and indirectly, an investment in Enbridge common shares. In the second quarter of 2013, the Board of Directors of Noverco authorized the sale of a portion of its Enbridge common share holding to rebalance Noverco's asset mix. On May 28, 2013, Noverco sold 15 million Enbridge common shares through a secondary offering. Enbridge's share of the net after-tax proceeds of approximately $248 million was received as dividends from Noverco on June 4, 2013 and was used to pay a portion of the Company's quarterly dividend on September 1, 2013. See *Liquidity and Capital Resources – Financing Activities.* A portion of this dividend did not qualify for the enhanced dividend tax credit in Canada and accordingly, was not designated as an "eligible dividend". The dividend was a "qualified dividend" for United States tax purposes.

Preference Share Issuances

Series 1

On March 27, 2013, the Company issued 16 million Preference Shares, Series 1 for gross proceeds of US$400 million. The 4.0% Cumulative Redeemable Preference Shares, Series 1 are entitled to receive a fixed, cumulative, quarterly preferential dividend of US$1.00 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for US$25.00 per share plus all accrued and unpaid dividends on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 1 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 2, subject to certain conditions, on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 2 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then three-month United States Government treasury bill rate plus 3.1%.

Series 3

On June 6, 2013, the Company issued 24 million Preference Shares, Series 3 for gross proceeds of $600 million. The 4.0% Cumulative Redeemable Preference Shares, Series 3 are entitled to receive a fixed, cumulative, quarterly preferential dividend of $1.00 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on September 1, 2019 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 3 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 4, subject to certain conditions, on September 1, 2019 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series 4 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 2.4%.

Series 5

On September 27, 2013, the Company issued eight million Preference Shares, Series 5 for gross proceeds of US$200 million. The 4.4% Cumulative Redeemable Preference Shares, Series 5 are entitled to receive a fixed, cumulative, quarterly preferential dividend of US$1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for US$25.00 per share plus all accrued and unpaid dividends on March 1, 2019 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 5 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 6, subject to certain conditions, on March 1, 2019 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 6 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then three-month United States Government treasury bill rate plus 2.8%.

Common Share Issuance

On April 16, 2013, the Company completed the issuance of 13 million Common Shares for gross proceeds of approximately $600 million. The proceeds were used to fund the Company's growth projects, reduce outstanding indebtedness, invest in subsidiaries and for general corporate purposes.

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				
Acquisition/Reversal/Expansion	US$1.3 billion	US$1.2 billion	2012-2013	Complete
Twinning/Extension	US$1.1 billion	US$0.4 billion	2014	Under construction
2. Suncor Bitumen Blend	$0.2 billion	$0.2 billion	2013	Complete
3. Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.4 billion	2013-2014 (in phases)	Under construction
4. Eastern Access[3]				
Toledo Expansion	US$0.2 billion	US$0.2 billion	2013	Complete
Line 9 Reversal and Expansion	$0.4 billion	$0.1 billion	2013-2014 (in phases)	Pre-construction
5. Eddystone Rail Project	US$0.1 billion	No significant expenditures to date	2014	Under construction
6. Norealis Pipeline	$0.5 billion	$0.4 billion	2014	Under construction
7. Flanagan South Pipeline Project	US$2.8 billion	US$0.8 billion	2014	Under construction
8. Canadian Mainline Expansion	$0.6 billion	$0.1 billion	2014-2015 (in phases)	Under construction
9. Surmont Phase 2 Expansion	$0.3 billion	$0.1 billion	2014-2015 (in phases)	Under construction
10. Athabasca Pipeline Twinning	$1.2 billion	$0.4 billion	2015	Under construction
11. Edmonton to Hardisty Expansion	$1.8 billion	$0.1 billion	2015	Pre-construction
12. Southern Access Extension	US$0.8 billion	US$0.1 billion	2015	Pre-construction
13. AOC Hangingstone Lateral	$0.1 billion	No significant expenditures to date	2015	Pre-construction
14. Canadian Mainline System Terminal Flexibility and Connectivity	$0.6 billion	$0.1 billion	2013-2015 (in phases)	Under construction
15. Woodland Pipeline Extension	$0.6 billion	$0.1 billion	2015	Pre-construction
16. JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
17. Wood Buffalo Extension	$1.6 billion	No significant expenditures to date	2017	Pre-construction
18. Norlite Pipeline System	$1.4 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. Massif du Sud Wind Project	$0.2 billion	$0.2 billion	2013	Complete

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
21. Saint Robert Bellarmin Wind Project	$0.1 billion	$0.1 billion	2013	Complete
22. Lac Alfred Wind Project	$0.3 billion	$0.3 billion	2013 (in phases)	Complete
23. Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2013	Complete
24. Cabin Gas Plant	$0.8 billion	$0.8 billion	To be determined	Deferred
25. Peace River Arch Gas Development	$0.3 billion	$0.2 billion	2012-2014 (in phases)	Under construction
26. Tioga Lateral Pipeline	US$0.1 billion	US$0.1 billion	2013	Complete
27. Venice Condensate Stabilization Facility	US$0.2 billion	US$0.1 billion	2013	Under construction
28. Blackspring Ridge Wind Project	$0.3 billion	$0.2 billion	2014	Under construction
29. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2014	Under construction
30. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.2 billion	2014	Under construction
31. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
SPONSORED INVESTMENTS				
32. EEP - Bakken Expansion Program	US$0.3 billion	US$0.3 billion	2013	Complete
33. The Fund - Bakken Expansion Program	$0.2 billion	$0.2 billion	2013	Complete
34. EEP - Berthold Rail Project	US$0.1 billion	US$0.1 billion	2013	Complete
35. EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.2 billion	2013	Complete
36. EEP - Bakken Access Program	US$0.1 billion	US$0.1 billion	2013	Complete
37. EEP - Texas Express NGL System	US$0.4 billion	US$0.3 billion	2013	Complete
38. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Under construction
39. EEP - Eastern Access[4]	US$2.6 billion	US$0.9 billion	2013-2016 (in phases)	Under construction
40. EEP - Lakehead System Mainline Expansion[4]	US$2.4 billion	US$0.1 billion	2014-2016 (in phases)	Under construction
41. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	No significant expenditures to date	2015	Pre-construction
42. EEP - Sandpiper Project	US$2.6 billion	No significant expenditures to date	2016	Pre-construction

1 *These amounts are estimates and subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge's share of joint venture projects.*
2 *Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to September 30, 2013.*
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.*

LIQUIDS PIPELINES

Seaway Crude Pipeline System

Acquisition of Interest

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline at a cost of approximately US$1.2 billion. Seaway Pipeline includes the 805-kilometre (500-mile) 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma.

Reversal and Expansion

The flow direction of the Seaway Pipeline was reversed, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. The initial reversal of the pipeline and preliminary service commenced in 2012, providing initial capacity of 150,000 barrels per day (bpd). Further pump station additions and modifications were completed in January 2013, increasing capacity available to shippers to up to approximately 400,000 bpd, depending on crude oil slate. Actual throughput experienced to date in 2013 has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P.'s (Enterprise) ECHO crude oil terminal (ECHO Terminal) in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013.

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 850,000 bpd in the first quarter of 2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into the ECHO Terminal.

In addition, a 137-kilometre (85-mile) pipeline will be constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. This extension will offer capacity of 560,000 bpd and, subject to regulatory approvals, is expected to be available in the first quarter of 2014.

Including the acquisition of the 50% interest in the Seaway Pipeline, Enbridge's total expected cost for the Seaway Pipeline is approximately US$2.4 billion. The acquisition, reversal and expansion are expected to cost US$1.3 billion, with the twinning, extension and lateral to the ECHO Terminal components of the project expected to cost approximately US$1.1 billion. Total expenditures incurred to date are approximately US$1.6 billion.

Suncor Bitumen Blend

Under an agreement with Suncor Energy Oil Sands Limited Partnership (Suncor Partnership), the Suncor Bitumen Blend project involved the construction of a new 350,000 barrel tank, new blend and diluent lines and pumping capacity to connect with Suncor Partnership's lines just outside Enbridge's Athabasca Tank Farm. Enbridge completed construction of the new facilities in June 2013, which enables Suncor Partnership to transport blended bitumen volumes from its Firebag production into the Wood Buffalo pipeline. The project was completed at an approximate cost of $0.2 billion.

South Cheecham Rail and Truck Terminal

The Company partnered with Keyera Corp. (Keyera) to construct the South Cheecham Rail and Truck Terminal (the Terminal), located approximately 75 kilometres (47 miles) southeast of Fort McMurray, Alberta. The Terminal, to be developed in phases, will be a multi-purpose hydrocarbon rail and truck terminal, designed to support bitumen producers within the Athabasca oil sands area and facilitate product moving in and out of the region. In addition to the facilities for handling diluent and diluted bitumen at the Terminal, the initial phase includes both a diluent and a diluted bitumen pipeline connection to Statoil Canada Limited's Cheecham Terminal which could be connected to Enbridge's existing Cheecham Terminal in the future. Construction of the first phase was completed and placed into service in October 2013 with post-completion expenditures expected to be incurred in the fourth quarter of 2013. The cost of the first phase is expected to be approximately $90 million and Enbridge's share of the project costs will be based upon its 50% joint venture interest. The construction of the additional phases of the Terminal is under active consideration by the Company and Keyera.

Athabasca Pipeline Capacity Expansion

The Company is undertaking an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oil Sands Project operated by Cenovus Energy Inc. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The estimated cost of the entire expansion is approximately $0.4 billion, with expenditures to date of approximately $0.4 billion. The initial expansion to 430,000 bpd of capacity was completed and placed into service in March 2013, with the remaining additional capacity of 140,000 bpd expected to be available in the first quarter of 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Eddystone Rail Project

The Company entered into a joint venture agreement with Canopy Prospecting Inc. to develop 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 will include leasing portions of a power generation facility and reconfiguring 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. Subject to regulatory and other approvals, the project is now targeted to be placed into service in the first quarter of 2014 and will receive and deliver an initial capacity of 80,000 bpd, expandable to 160,000 bpd. The total estimated cost of the project is approximately US$0.1 billion and Enbridge's share of the project costs will be based upon its 75% joint venture interest.

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky Energy Inc. operated Sunrise Energy Project, the Company is undertaking construction of 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 estimated cost of the project is approximately $0.5 billion, with expenditures to date of approximately $0.4 billion. The project is expected to be substantially completed by the end of 2013 and available for service in 2014.

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. On August 23, 2013, the Sierra Club and National Wildlife Federation filed a Complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court). 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 enjoining Enbridge from continuing construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. On September 5, 2013, Enbridge obtained intervener status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction. The Court hearing was held on September 27, 2013, but no decision has yet been released. Subject to regulatory and other approvals, the pipeline is expected to be in service in the third quarter of 2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$0.8 billion.

Canadian Mainline Expansion

Enbridge is undertaking an estimated $0.2 billion expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by 120,000 bpd to a capacity of 570,000 bpd and is expected to be in service in the third quarter of 2014.

In January 2013, Enbridge announced a further expansion of the Canadian Mainline system between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba, at an estimated cost of $0.4 billion. Subject to NEB approval, the scope of the additional expansion involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by another 230,000 bpd to its full capacity of 800,000 bpd and is expected to be in service in 2015.

The total estimated cost for the Canadian Mainline Expansion is $0.6 billion, with expenditures to date of approximately $0.1 billion. Delays in receipt of the applicable regulatory approvals on EEP's portion of the mainline system expansion could affect the target in-service dates of the Canadian Mainline Expansion. See *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

Surmont Phase 2 Expansion
In May 2013, the Company announced it had entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. and Total E&P Canada Ltd. (the ConocoPhillips Surmont 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 the twinning of the southern section of the Company's 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 $0.4 billion, will include 346 kilometres (215 miles) of 36-inch pipeline adjacent to the existing Athabasca Pipeline right-of-way. The initial annual capacity of the pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the line is now expected to enter service in the third quarter of 2015.

Edmonton to Hardisty Expansion
The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project, with an estimated cost of approximately $1.8 billion, and expenditures incurred to date of approximately $0.1 billion, will include 181 kilometres (112 miles) of new 36-inch diameter pipeline, expected to generally follow the same route as Enbridge's existing Line 4 pipeline, and new terminal facilities in Edmonton which include five new 500,000 barrel tanks and connections into existing infrastructure at Hardisty Terminal. The initial capacity of the new line will be approximately 570,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015.

Southern Access Extension
The Southern Access Extension project will consist of the construction of a new 265-kilometre (165-mile) 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois 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 2015 at an approximate cost of US$0.8 billion, with expenditures to date of approximately US$0.1 billion. The initial capacity of the new line is expected to be approximately 300,000 bpd. Prior to the binding open season that closed in January 2013, Enbridge had received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline. In June 2013, a second open season to solicit additional capacity commitments from shippers was announced and subsequently closed in September 2013. The Company has received a further capacity commitment through the second open season, which can be accommodated within the initial capacity planned for the pipeline.

AOC Hangingstone Lateral
In March 2013, the Company announced that it 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 47-kilometre (29-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. 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. Subject to regulatory and other approvals, the Phase I facilities are expected to be placed into service in 2015. With the scope for Phase I finalized in June 2013, the estimated cost of the project is now approximately $0.1 billion.

Canadian Mainline System Terminal Flexibility and Connectivity
As part of the Light Oil Market Access Program initiative, the Company is undertaking the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The cost of the project is expected to be approximately $0.6 billion, with expenditures incurred to date of approximately $0.1 billion, and with varying completion dates expected between 2013 and 2015 related to existing terminal facility modifications. These modifications are comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections.

Woodland Pipeline Extension
In July 2013, Enbridge announced that it had received shipper sanctioning for the Woodland Pipeline Extension Project. The joint venture 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 $0.1 billion. Subject to finalization of scope and a definitive cost estimate, the project has a target in-service date of 2015.

JACOS Hangingstone Project
In September 2013, Enbridge announced it will construct 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 finalization of definitive agreements and regulatory approvals, 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. Subject to finalization of scope, which could include an optional 8-inch diluent line to transport diluent to the JACOS Hangingstone project site, 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 early 2016.

Wood Buffalo Extension
In October 2013, Enbridge announced that it was selected by Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), as well as the 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 pipeline will be an extension of Enbridge's existing Wood Buffalo Pipeline which would include the 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
In October 2013, Enbridge announced it will develop the Norlite Pipeline System, a new industry diluent pipeline to meet the needs of multiple producers in the Athabasca oil sands region. Subject to finalization of scope, the 16-inch diameter base scope of the project will be anchored by throughput commitments

from both the Fort Hills Partners for volumes for the proposed Fort Hills Project and the Suncor Partnership's proprietary oil sands production. If Enbridge is successful in securing additional long term commitments on the proposed Norlite Pipeline System, the scope of the project could be increased to a 20-inch to 24-inch diameter pipeline system. The proposed Norlite Pipeline System will involve the construction of a new 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, as well as a potential new lateral pipeline to Enbridge's Norealis Terminal that is currently under construction. The Norlite Pipeline System has the right to access certain existing capacity on 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. Subject to regulatory approvals, the Norlite Pipeline System is expected to be completed in 2017 at an estimated cost of approximately $1.4 billion, and will provide capacity of 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 by the addition of pump stations.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD plans to expand its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.7 billion, the proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. The Company filed amended applications reflecting scope modifications with the Ontario Energy Board (OEB) in February, April and July 2013. As a result of the July scope modification, the expected capital cost increased by approximately $0.1 billion. OEB hearings were held in September and October 2013 and, subject to OEB approval, construction is targeted to start in late 2014, with completion expected by the end of 2015.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Massif du Sud Wind Project

Enbridge secured a 50% interest in the 150-megawatt (MW) Massif du Sud Wind Project (Massif du Sud), located 100 kilometres (60 miles) east of Quebec City, Quebec. Massif du Sud delivers energy to Hydro-Quebec under a 20-year power purchase agreement (PPA). Project construction was completed in December 2012 at a final cost of approximately $0.2 billion and commercial operation commenced in January 2013.

Saint Robert Bellarmin Wind Project

In July 2013, Enbridge announced it had reached an agreement with EDF Energy Nouvelles Canada Development Inc. to acquire a 50% interest in the 80-MW Saint Robert Bellarmin Wind Project, located 300 kilometres (185 miles) east of Montreal, Quebec. The project is operational and power output is being delivered to Hydro-Quebec under a 20-year PPA. The Company's total investment in the project is approximately $0.1 billion.

Lac Alfred Wind Project

Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred), located 400 kilometres (250 miles) northeast of Quebec City in Quebec's Bas-Saint-Laurent region. Lac Alfred delivers energy to Hydro-Quebec under a 20-year PPA. The project was constructed under a fixed price, turnkey, engineering, procurement and construction agreement. Construction was completed and commercial operations commenced in two phases: Phase 1 in January 2013 and Phase 2 in August 2013, with each phase providing 150-MW of generation capacity. The Company's total investment in the project was approximately $0.3 billion.

Montana-Alberta Tie-Line

In September 2013, Enbridge completed and placed into service the first 300-MW phase of Montana-Alberta Tie-Line (MATL). MATL is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and buoyant power demand in Alberta. Post-completion expenditures will be incurred throughout 2013 and the estimated cost for the first phase of the project is approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. The expansion of the additional 300-MW of transmission is under active consideration and an in-service date and definitive cost estimate are dependent on finalization of scope, regulatory approval and customer support.

Cabin Gas Plant

In 2011, the Company secured a 71% interest in the development of the Cabin Gas Plant (Cabin), located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company's total investment in phases 1 and 2 of Cabin was expected to be approximately $1.1 billion. In October 2012, the Company and its partners announced plans to defer both the commissioning of phase 1 and the construction of phase 2. Under the deferral, the Company's total investment in phases 1 and 2 is expected to be approximately $0.8 billion, with expenditures to date of approximately $0.8 billion. Expenditures will be incurred throughout 2013 to complete pre-commission construction on Phase 1 and to place Phase 2 into preservation mode. In December 2012, Enbridge started earning fees for its investment made to date in both phases 1 and 2 of Cabin. On May 1, 2013, the Company became operator of Cabin.

Peace River Arch Gas Development

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities. These facilities, which are either currently in service or under construction, are located in the Peace River Arch (PRA) region of northwest Alberta. The project will be completed in phases with new gathering lines and NGL handling facilities expected to be completed by the second quarter of 2014. Enbridge's investment in the PRA Gas Development is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.2 billion. Enbridge also retains an exclusivity to work with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region. Financial terms of the PRA Gas Development are substantially consistent with previously established terms of the Cabin development.

Tioga Lateral Pipeline

The United States portion of the Alliance Pipeline (Alliance Pipeline US) has completed construction of a natural gas pipeline lateral and associated facilities to connect production from the Hess Corporation's (Hess) Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. The 127-kilometre (79-mile) Tioga Lateral Pipeline went into service in September 2013 and will facilitate movement of liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of Alliance. The pipeline has an initial design capacity of approximately 126 million cubic feet per day (mmcf/d), which can be expanded based on shipper demand. Through its 50% ownership interest in Alliance Pipeline US, Enbridge's cost of the project is approximately US$0.1 billion. In October 2012, Alliance Pipeline US executed a contract with Hess as an anchor shipper. Aux Sable Liquids Products and Hess reached a concurrent agreement for the provision of NGL services.

Venice Condensate Stabilization Facility

The Company is carrying out an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility at its Venice, Louisiana facility within Enbridge Offshore Pipelines (Offshore). Expenditures to date are approximately US$0.1 billion. The expanded condensate processing capacity is required to accommodate additional natural gas production from the Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge's onshore facility at Venice via Enbridge's Mississippi Canyon offshore pipeline system, where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

Blackspring Ridge Wind Project

In April 2013, the Company announced that it had secured a 50% interest in the development of the 300-MW Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project is being constructed under a fixed price engineering, procurement and construction contract and is expected to be completed 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 contracts. The Company's total investment in the project is expected to be approximately $0.3 billion, with expenditures incurred to date of approximately $0.2 billion.

Big Foot Oil Pipeline

Under agreements with Chevron USA Inc. (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 proposed Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's undertaking of the Walker Ridge Gas Gathering System (WRGGS) construction, discussed below. Upon completion of the project, Enbridge will operate the Big Foot Oil 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, and an expected in-service date in the fourth quarter of 2014.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the WRGGS to provide natural gas gathering services to the proposed 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 mmcf/d. The Jack St. Malo and Big Foot portions of the WRGGS are expected to be placed into service in the third and fourth quarters of 2014, respectively. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.2 billion.

Heidelberg Lateral Pipeline

The Company will construct, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation (Anadarko), to an existing third-party system. The Heidelberg Lateral Pipeline (Heidelberg), a 20-inch 58-kilometre (36-mile) pipeline, 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

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing crude oil production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba was undertaken by EEP and the Fund. The project, undertaken by EEP in the United States and the Fund in Canada, reversed and expanded an existing pipeline, running from Berthold, North Dakota, to Steelman, Saskatchewan, and constructed a new 16-inch pipeline from a new terminal near Steelman to the Enbridge mainline terminal near Cromer, Manitoba. The project was completed and entered service in March 2013, providing capacity of 145,000 bpd. The United States portion of the project was completed at an approximate cost of US$0.3 billion and the Canadian portion of the project was completed at an approximate cost of $0.2 billion.

Enbridge Energy Partners, L.P.

Berthold Rail Project

The Berthold Rail project expanded capacity into the Berthold Terminal in North Dakota by 80,000 bpd and involved the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing infrastructure. The first phase of terminal facilities was completed in 2012, providing additional capacity of 10,000 bpd to the Berthold Terminal. The loading facility and crude oil tankage were subsequently completed and placed into service in March 2013. The total cost of the project was approximately US$0.1 billion.

Ajax Cryogenic Processing Plant

In September 2013, EEP placed into service the Ajax Plant, comprised of a newly constructed natural gas processing plant and related facilities, on its Anadarko System. The Ajax Plant provides capacity of 150 mmcf/d and, in conjunction with the Allison Plant, has increased total processing capacity on the Anadarko System to approximately 1,150 mmcf/d. The Anadarko System's condensate stabilization capacity was also increased by approximately 2,000 bpd. With the Texas Express NGL System completed in October 2013 as discussed below, the Ajax Plant is capable of producing approximately 15,000 bpd of NGL. The total cost of the Ajax Plant project was approximately US$0.2 billion.

Bakken Access Program

The Bakken Access Program represents an upstream expansion that will further complement EEP's Bakken expansion. The Bakken Access Program was placed into service in phases in the middle of 2013 and enhances crude oil gathering capabilities on the North Dakota System by 100,000 bpd. The program involved increasing pipeline capacity, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota at an approximate cost of US$0.1 billion.

Texas Express NGL System

In October 2013, EEP, Enterprise, Anadarko and DCP Midstream Partners, L.P. (DCP Midstream) announced the Texas Express NGL System was placed into service. The Texas Express NGL System is a joint venture that was created to design and construct a new NGL pipeline and NGL gathering system. The NGL pipeline is a joint venture between EEP, Enterprise, Anadarko and DCP Midstream and the NGL gathering system is a joint venture between EEP, Enterprise and Anadarko. Enterprise constructed and operates the NGL pipeline, while EEP constructed and operates the NGL gathering system. Post-completion expenditures will be incurred throughout 2013 and EEP's investment in the Texas Express NGL System remains at approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

The Texas Express NGL System originates in Skellytown, Texas and extends approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. The Texas Express NGL System has an initial capacity of approximately 280,000 bpd, expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline. The new NGL gathering system consists of approximately 187 kilometres (116 miles) of gathering lines that connect the Texas Express NGL System to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, as well as to the central Texas Barnett Shale processing plants.

Line 6B 75-Mile Replacement Program

This program includes 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 are being completed in components, with approximately 104 kilometres (65 miles) of segments placed in service since the first quarter of 2013. The two remaining 8-kilometre (5-mile) segments in Indiana are now expected to be placed in service in the first quarter of 2014. The total estimated capital for this replacement program is approximately US$0.4 billion, with expenditures to date of approximately US$0.4 billion. EEP will recover 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 several Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. The current scope of Enbridge projects includes a reversal of its Line 9 and expansion of the Toledo Pipeline. The current scope of EEP projects includes an expansion of its Line 5 as well as United States mainline system expansions involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. The individual projects are further described below.

In August 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 also plans to undertake 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 is expected to be completed at an estimated cost of approximately $0.3 billion, including estimated costs associated with integrity digs being performed on the line. 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, which is expected to be completed at an estimated cost of approximately $0.1 billion. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd. Subject to NEB approval, the Line 9B reversal and Line 9B capacity expansion are expected to be available for service in the fourth quarter of 2014 at a total estimated cost of approximately $0.4 billion. Expenditures incurred to date for the Lines 9A and 9B projects are approximately $0.1 billion.

In May 2013, Enbridge completed an 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 May 2013, EEP completed and placed into service the expansion of its Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario. The Line 5 expansion increased capacity by 50,000 bpd at an approximate cost of US$0.1 billion.

EEP is also undertaking the expansion of its Line 62 between Flanagan, Illinois and Griffith, Indiana by adding horsepower to increase capacity from 130,000 bpd to 235,000 bpd and adding a 330,000 barrel tank at Griffith. The Line 62 capacity expansion project was completed and placed into service in November 2013. EEP also plans to replace additional sections of Line 6B in Indiana and Michigan, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline will be replaced with 36-inch diameter pipe. Subject to regulatory and other approvals, the target in-service date for this Line 6B project is now expected to be the third quarter of 2014. The replacement of the Line 6B sections is in addition to the Line 6B Replacement Program discussed previously. The expected cost of the United States mainline expansions is approximately US$2.2 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

The Eastern Access Expansion 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 involve the addition of new pumps, existing station modifications and breakout tankage at the Griffith and Stockbridge terminals. Subject to regulatory and other approvals, the project is expected to be placed into service in 2016 at an estimated capital cost of approximately US$0.4 billion.

The total estimated cost of the United States mainline expansions, including the Line 5 expansion and the Line 6B capacity expansion project, is approximately US$2.6 billion, with expenditures to date of approximately US$0.9 billion. The Eastern Access projects, excluding the Toledo Expansion and Line 9 Reversal and Expansion, are now being funded 75% by Enbridge and 25% by EEP, after EEP exercised the option to reduce its funding and associated economic interest in the project by 15% on June 28, 2013. 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 15%. For further discussion refer to *Liquidity and Capital Resources*.

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. Included in the expansion are 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. In January 2013, EEP announced a further expansion of the Lakehead System mainline between the border and Superior to increase capacity from 570,000 bpd to 800,000 bpd, at an estimated capital cost of approximately US$0.2 billion. 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 is the third quarter of 2014 for the initial phase and 2015 for the second phase. Delays in receipt of the applicable regulatory approvals could affect the target in-service dates. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower and no pipeline construction.

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 at an estimated capital cost of approximately US$1.3 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 finalization of scope and 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$2.4 billion, with expenditures incurred to date of approximately US$0.1 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is now being funded 75% by Enbridge and 25% by EEP, after EEP exercised the option to reduce its funding and associated economic interest in the project by 15% on June 28, 2013. 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 15%. For further discussion refer to *Liquidity and Capital Resources*.

Beckville Cryogenic Processing Facility

In April 2013, EEP announced plans to construct a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas, at an expected cost of approximately US$0.1 billion. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where EEP’s 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 construction of the plant and associated facilities is anticipated to begin in late 2013, with an expected in-service date of 2015.

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 original expansion would involve construction of a 965-kilometre (600-mile) 24-inch diameter line from Beaver Lodge, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the 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 Beaver Lodge and Clearbrook and 375,000 bpd of capacity between Clearbrook and Superior. In September 2013, a scope modification was made to increase the twin line diameter from 24-inches to 30-inches between Clearbrook and Superior.

As a result of the September 2013 scope modification, the expected capital cost increased by approximately US$0.1 billion and Sandpiper is now expected to cost approximately US$2.6 billion and will be fully funded by EEP. A petition was filed with the Federal Energy Regulatory Commission (FERC) to approve recovery of Sandpiper's costs through a surcharge to the Enbridge Pipelines (North Dakota) LLC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. On March 22, 2013, the FERC denied the petition on procedural grounds. EEP plans to re-file its petition with modifications to address the FERC's concerns. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals as well as finalization of scope.

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 a large number of 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

Eastern Gulf Crude Access Pipeline

The memorandum of understanding (MOU) between the Company and Energy Transfer Partners, L.P. has expired and the Company no longer has the right to purchase into the Eastern Gulf Crude Access Pipeline. The proposed project would have provided access to the eastern Gulf Coast refinery market from the Patoka, Illinois hub. The MOU expired without satisfaction of its condition with respect to throughput commitments and FERC approval of conversion from natural gas service to crude oil of certain segments of pipeline that are currently in operation. The Company believes there is demand for transportation service from the United States midwest to the eastern Gulf Coast refinery market and will continue to assess future opportunities to meet potential shipper needs, including a revised Eastern Gulf Crude Access Pipeline joint venture.

Northern Gateway Project

The 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 import condensate and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

Northern Gateway submitted an application to the NEB in May 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. Following sessions with the public, including Aboriginal groups, and the provision of additional information by Northern Gateway, the JRP issued a Hearing Order in May 2011 outlining the procedures to be followed.

In August 2011, Northern Gateway filed commercial agreements with the NEB which provide for committed long-term service and capacity on both the proposed crude oil export and condensate import pipelines. Capacity has also been reserved for use by uncommitted shippers.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the JRP would hear all oral evidence from registered intervenors first, followed by oral statements from registered participants. Community hearings for oral evidence and statements took place between January and August 2012 in various communities. A written record of what was said each day in the community hearings is available on the JRP's website. Intervenors responded to questions by Northern Gateway on July 6, 2012. Northern Gateway filed reply evidence to the evidence of the intervenors on July 20, 2012. The reply evidence contained details of further enhancements in pipeline design and operations. These extra measures are estimated to cost an additional $400 million to $500 million. The enhancements include: increasing pipeline wall thickness of the oil pipeline; additional pipeline wall thickness for water crossings such as major tributaries to the Fraser, Skeena and Kitimat

Rivers; increasing the number of remotely-operated isolation valves by 50% within British Columbia to protect high-value fish habitat; increasing frequency of in-line inspection surveys across the entire Northern Gateway pipeline system by a minimum of 50% over and above current standards; installing dual leak detection systems; and staffing pump stations in remote locations on a 24 hour/7 day basis for on-site monitoring, heightened security and rapid response to abnormal conditions.

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 tunneling 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. The revised estimate is anticipated to be completed in the first quarter of 2014.

The final hearings commenced on September 4, 2012 where Northern Gateway, intervenors, government participants and the JRP questioned those who have presented oral or written evidence. In April 2013, the JRP issued its potential conditions if the project were to be approved. The issuance does not indicate an expectation the proposed project will be approved, but permitted all parties to provide comments or to suggest additional conditions for the JRP to consider.

Written final argument was filed on May 31, 2013. The final hearings for oral argument concluded June 24, 2013. The JRP has announced it expects to issue its reports and findings on the proposed project by December 2013.

Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. 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.

On February 23, 2012, Transport Canada published its TERMPOL Review Process Report of the Northern Gateway's proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: "While there will always be residual risk in any project, after reviewing the proponent's studies and taking into account the proponent's commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway." The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. The Gitxaala First Nations (Gitxaala) filed a Notice of Judicial Review with the Federal Court of Canada challenging the TERMPOL process on the grounds that there had not been adequate consultation with the Gitxaala with respect to the potential impacts on its rights and title resulting from the routine operation of the tankers servicing the Northern Gateway terminal in Kitimat. Following the hearing, the Federal Court of Canada issued a decision rejecting the Gitxaala challenge noting that it was premature for the Court to intervene in the process before it has reached a conclusion. The Federal Court of Canada decision has not been appealed.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.3 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 Enbridge also maintains a Northern Gateway website in addition to information available on www.enbridge.com. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway Community Social Responsibility Report are available on www.northerngateway.ca. ***None of the information contained on, or connected to, the JRP website, the Northern Gateway website or Enbridge's website is incorporated in or otherwise part of this MD&A.***

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

NEXUS Gas Transmission Project

In 2012, Enbridge, DTE Energy Company (DTE) and Spectra Energy Corp (Spectra) announced the execution of a MOU to jointly develop the NEXUS Gas Transmission System (NEXUS), a project that would move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan, and Ontario, Canada. The proposed NEXUS project would originate in northeastern Ohio, include approximately 400 kilometres (250 miles) of large diameter pipe, and be capable of transporting one billion cubic feet per day of natural gas. The line would follow existing utility corridors to an interconnect in Michigan and utilize the existing Vector Pipeline (Vector) to reach the Ontario market. Upon completion, Spectra would become a 20% owner in Vector, a joint venture between DTE and Enbridge. The partners continue to monitor Utica shale development progress awaiting increased interest by producers in accessing the Ohio/Michigan/Ontario market.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Canadian Mainline	**112**	120	**341**	315
Regional Oil Sands System	**38**	31	**115**	81
Southern Lights Pipeline	**15**	9	**36**	30
Seaway Pipeline	**9**	11	**38**	13
Spearhead Pipeline	**8**	8	**25**	30
Feeder Pipelines and Other	**5**	8	**10**	9
Adjusted earnings	**187**	187	**565**	478
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**133**	90	**(125)**	83
Canadian Mainline - Line 9 tolling adjustment	**-**	-	**-**	6
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(13)**	-	**(53)**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**(37)**	-	**(37)**	-
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**31**	-	**31**	-
Spearhead Pipeline - changes in unrealized derivative fair value loss	**-**	(1)	**-**	-
Earnings attributable to common shareholders	**301**	276	**381**	567

Canadian Mainline

Canadian Mainline adjusted earnings decreased for the three months ended September 30, 2013 compared with the third quarter of 2012 due to a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. The Canadian Mainline IJT Residual Benchmark Toll is inversely correlated to the Lakehead System Toll which was higher due to increased costs in relation to EEP's growth projects which will be recovered through the Lakehead System's rate structure. The effect of the lower Canadian Mainline IJT Residual Benchmark Toll was partially offset by higher throughput; however, longer than expected refinery shutdowns and the delay in the start-up of a refinery conversion to heavy oil curtailed further delivery of western Canadian crude to the United States midwest refinery market and limited throughput growth in the third quarter of 2013. The tempered growth in demand from refineries is expected to persist until the first quarter of 2014. Also contributing to lower adjusted earnings were higher depreciation expense and interest expense.

Adjusted earnings on Canadian Mainline increased for the nine months ended September 30, 2013 compared with the corresponding period of 2012. This increase was primarily driven by higher throughput as steady production from the oil sands in Alberta was priced at levels which displaced other non-Canadian production from the midwest market and drove increased long-haul barrels on Canadian Mainline, though limited by United States midwest refinery shutdowns. Offsetting increased throughput was a lower Canadian Mainline IJT Residual Benchmark Toll in both the second and third quarters of 2013, respectively, compared with the corresponding 2012 periods. Adjusted earnings for the first nine months of 2013 compared with the first nine months of 2012 also reflected an increase in operating and administrative costs, primarily due to higher employee costs, as well as higher depreciation and interest expense.

Supplemental information on Canadian Mainline adjusted earnings for the three months and nine months ended September 30, 2013 and 2012 is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Revenues	**353**	355	**1,064**	1,011
Expenses				
Operating and administrative	**90**	93	**303**	283
Power	**31**	31	**86**	86
Depreciation and amortization	**62**	54	**180**	163
	183	178	**569**	532
	170	177	**495**	479
Other income/(expense)	**(3)**	(3)	**1**	(6)
Interest expense	**(42)**	(36)	**(122)**	(101)
	125	138	**374**	372
Income taxes	**(13)**	(18)	**(33)**	(57)
Adjusted earnings	**112**	120	**341**	315
Effective United States to Canadian dollar exchange rate[1]	**1.000**	0.975	**0.999**	0.970

September 30,	**2013**	2012
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$3.98**	$3.94
Lakehead System Local Toll[3]	**$2.18**	$1.85
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.80**	$2.09

1 *Inclusive of realized gains or 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 July 1, 2012, this toll increased from US$1.76 to US$1.85 and effective April 1, 2013, it subsequently increased to US$2.13. Effective July 1, 2013, this toll increased from US$2.13 to US$2.18.*

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, effective July 1, 2013, this toll decreased from US$1.81 to US$1.80. 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 September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
Throughput[1] *(thousand barrels per day (kbpd))*	**1,736**	1,617	**1,707**	1,654

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

Regional Oil Sands System

Regional Oil Sands System adjusted earnings increased for the three and nine months ended September 30, 2013 compared with the same periods of 2012 primarily as a result of higher contracted volumes on the Athabasca pipeline, higher capital expansion fees on the Waupisoo pipeline and new assets placed into service in late 2012, including the Woodland and Wood Buffalo pipelines. Partially offsetting these earnings increases were higher operating and administrative costs, higher depreciation expense due to the commissioning of new assets and a decrease in Hardisty Caverns earnings following the sale to the Fund in the fourth quarter of 2012.

Southern Lights Pipeline

Southern Lights Pipeline earnings increased for the three and nine months ended September 30, 2013 compared with the corresponding 2012 period primarily due to the timing of recognition of recoveries under a cost of service model.

Seaway Pipeline

Seaway Pipeline earnings for the nine months ended September 30, 2013 were higher compared with the corresponding 2012 period due to a full nine months of operations and increased throughput capacity available on the pipeline in 2013. Seaway Pipeline was completed in May 2012 providing initial capacity of 150,000 bpd. In January 2013, the completion of further pump station additions and modifications increased the capacity available to shippers to up to 400,000 bpd, depending on crude slate. Actual throughput experienced in the first nine months of 2013 was curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to the ECHO Terminal in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013. However, a narrowing West Texas Intermediate to Louisiana Light Sweet crude oil spread is discouraging spot volumes on Seaway Pipeline. For the third quarter of 2013, Seaway Pipeline earnings were lower than the comparative 2012 period due to higher financing costs.

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

FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (ALJ) was released finding that the uncommitted and committed rates on Seaway Pipeline should be reduced to reflect the ALJ’s findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013 challenging the ALJ’s decision and asking for expedited ruling by the FERC on the committed rates. There is no prescribed time line for a ruling from the FERC.

Spearhead Pipeline

Spearhead Pipeline adjusted earnings for the three months ended September 30, 2013 were comparable with the corresponding 2012 period due to offsetting reasons. Higher contributions from increased demand at Cushing, Oklahoma for further transportation on the Seaway Pipeline to the Gulf Coast refining market as well as higher expiry of shipper make-up rights were offset by higher operating expenses, mainly higher power costs, from the increased transportation of heavy crude.

Adjusted earnings for the nine months ended September 30, 2013 decreased compared with the nine months ended September 30, 2012 as incremental increase in volumes on Spearhead Pipeline, as mentioned above, were more than offset by lower expiry of shipper make-up rights and higher operating expenses, predominantly higher power costs and higher pipeline integrity expenditures.

Feeder Pipelines and Other
Earnings decreased in Feeder Pipelines and Other in the third quarter of 2013 compared with the comparative 2012 period due to higher business development costs not eligible for capitalization. This decrease was partially offset by higher earnings from the Toledo Pipeline expansion completed in May 2013. For the nine months ended September 30, 2013 the same trends existed for business development costs, however, this was more than offset by higher volumes and tolls on Olympic pipeline.

Liquids Pipelines earnings were impacted by the following adjusting items:
- Canadian Mainline earnings for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage risk exposures inherent within the Competitive Toll Settlement, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline earnings for 2012 included a Line 9 tolling adjustment related to services provided in prior periods.
- Regional Oil Sands System earnings for 2013 included a charge related to the Line 37 crude oil release which occurred in June 2013. See *Recent Developments – Liquids Pipelines – Line 37 Crude Oil Release.*
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts. 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, regardless of volumes shipped.
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to correct deferred income tax expense and to correct the rate at which deemed taxes are recovered under a long-term contract.
- Spearhead Pipeline earnings for the third quarter of 2012 included unrealized fair value loss on derivative financial instruments used to manage exposures to allowance oil commodity prices.

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**(26)**	(17)	**97**	93
Other Gas Distribution and Storage	**(3)**	(1)	**12**	20
Adjusted earnings/(loss)	**(29)**	(18)	**109**	113
EGD - gas transportation costs out-of-period adjustment	**(56)**	-	**(56)**	-
EGD - warmer than normal weather	**-**	-	**(4)**	(24)
EGD - tax rate changes	**-**	-	**-**	(9)
Earnings/(loss) attributable to common shareholders	**(85)**	(18)	**49**	80

EGD's operating results for 2013 are pursuant to a one year cost of service settlement, following completion of a five year Incentive Regulation (IR) term at the end of 2012. Adjusted earnings increased for the nine month period ended September 30, 2013 compared with the corresponding 2012 period due primarily to customer growth, lower depreciation and amortization expense and the absence of earnings sharing in 2013. Higher operating and administrative costs, including employee related costs and operational and safety costs, partially offset the favourable revenue and depreciation impacts. The negative contribution in the third quarter primarily reflects the inherent seasonality in EGD's operations where the majority of earnings are achieved in the colder months of the year. Adjusted earnings for the third quarter of 2013 included an adjustment to gas transportation costs of $15 million related to the first half of 2013.

In July 2013, EGD filed an application with the OEB for the setting of rates through a customized IR mechanism for the period 2014 through 2018. A decision is anticipated in the second quarter of 2014.

Other Gas Distribution and Storage earnings decreased for the first nine months of 2013 as a result of lower rates from the revised rate setting methodology that became effective October 1, 2012 in Enbridge Gas New Brunswick (EGNB).

The Company commenced legal proceedings against the Government of New Brunswick, seeking damages for breach of contract, in April 2012. The Company also commenced a separate application to the New Brunswick Court of Queen's Bench to quash the Government's rates and tariffs regulation in May 2012. The Court of Queen's Bench dismissed the application in August 2012, but the Company appealed this decision to the New Brunswick Court of Appeal. EGNB's appeal was successful in part, as the Court of Appeal ruled that the part of the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor-in-Council. The Court of Appeal upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. As a result of this outcome, EGNB applied on June 14, 2013 to the New Brunswick Energy and Utilities Board (EUB) for new rates, effective July 1, 2013, for commercial and industrial customers. On July 26, 2013, the EUB granted EGNB's application for new rates, but with an effective date of August 1, 2013. The EUB's decision will enable EGNB to fully recover its revenue requirement from August 1, 2013 until the next rate period. Accordingly, EGNB has also indefinitely adjourned its application for judicial review of the EUB's original decision regarding rates to take effect as of October 1, 2012. EGNB filed its 2014 rate application on October 1, 2013, the outcome of which will determine rates during the next rate period. There is no assurance that any of EGNB's legal proceedings against the Province of New Brunswick will be successful or will result in any recovery.

Gas Distribution earnings were impacted by the following adjusting items:

- EGD earnings/(loss) for 2013 reflected an out-of-period correction to gas transportation costs which had previously been deferred.
- EGD earnings/(loss) were adjusted to reflect the impact of weather.
- EGD earnings/(loss) for 2012 reflect the impact of unfavourable tax rate changes.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Aux Sable	**16**	21	**32**	47
Energy Services	**19**	9	**94**	31
Alliance Pipeline US	**10**	11	**31**	30
Vector Pipeline	**5**	5	**18**	16
Enbridge Offshore Pipelines (Offshore)	**(4)**	(1)	**(4)**	-
Other	**8**	1	**15**	10
Adjusted earnings	**54**	46	**186**	134
Aux Sable - changes in unrealized derivative fair value gains/(loss)	**-**	(8)	**-**	15
Energy Services - changes in unrealized derivative fair value gains/(loss)	**18**	(232)	**131**	(558)
Other - changes in unrealized derivative fair value gains/(loss)	**(4)**	3	**(60)**	-
Earnings/(loss) attributable to common shareholders	**68**	(191)	**257**	(409)

Aux Sable adjusted earnings decreased in the third quarter of 2013 compared with 2012 as the trends experienced in the first half of 2013 persisted, mainly lower fractionation margins and lower ethane processing volumes due to ethane reinjections. Lower fractionation margins resulted in a decrease in contributions from the upside sharing mechanism in Aux Sable's production sales agreement compared with the three and nine months ended September 30, 2012.

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. Energy Services adjusted earnings increased for the three and nine month periods ended September 30, 2013 compared with the same periods of 2012 due to wide location and crude grade differentials, which gave rise to additional and more profitable margin opportunities. However, the rate of adjusted earnings increase was lower in the third quarter of 2013 as market conditions were less favourable than the first half of the year.

Offshore earnings for the first nine months of 2013 remained weak as low volumes persisted on the majority of its pipelines due to decreased production in the Gulf of Mexico. The volume weakness is expected to continue in the short-term and the Company expects Offshore to be in a loss position for the full year. Effective May 1, 2013, the Company elected to not renew windstorm (hurricane) coverage on its Offshore asset portfolio. The Company expects to reassess the market for windstorm coverage and revisit the possible purchase of coverage in future years.

Adjusted earnings from Other increased for the three and nine months ended September 30, 2013 compared with the corresponding periods of 2012 due to new wind farms placed into service in 2013, contributions from fees earned on the Company's investment in Cabin, for which earnings recognition commenced in December 2012, and lower business development costs not eligible for capitalization. Partially offsetting the increase in adjusted earnings was the transfer of certain renewable energy assets to the Fund in December 2012, as well as lower contributions from the Cedar Point Wind Energy Project due to lower wind resources.

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

- Aux Sable earnings for 2012 reflected changes in the fair value of unrealized derivative financial instruments related to the Company's forward gas processing risk management position.

- Energy Services earnings/(loss) for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory. 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.
- Adjusted earnings for 2013 excluded a one-time realized loss of $58 million incurred to close out derivative contracts used to hedge forecasted Energy Services transactions which are no longer probable to occur.
- Other earnings/(loss) for 2013 and 2012 reflected changes in unrealized fair value on derivative financial instruments. In 2013, the unrealized loss reflected the change in the value of long-term power price derivative contracts acquired to hedge expected revenues and cash flows from Blackspring Ridge.

SPONSORED INVESTMENTS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Enbridge Energy Partners, L.P. (EEP)	**46**	41	**119**	109
Enbridge Energy, Limited Partnership (EELP) - Alberta Clipper US	**8**	10	**24**	32
Enbridge Income Fund (the Fund)	**32**	18	**81**	55
Adjusted earnings	**86**	69	**224**	196
EEP - leak insurance recoveries	**-**	24	**6**	24
EEP - leak remediation costs	**(5)**	(7)	**(35)**	(9)
EEP - changes in unrealized derivative fair value gains/(loss)	**(6)**	(6)	**(3)**	1
EEP - tax rate differences/changes	**-**	-	**(3)**	-
EEP - NGL trucking and marketing investigation costs	**-**	-	**-**	(1)
Earnings attributable to common shareholders	**75**	80	**189**	211

EEP adjusted earnings increased for the three and nine months ended September 30, 2013 compared with the corresponding 2012 periods due to distributions received from Enbridge's May 2013 investment in preferred units of EEP and higher incentive distributions. Partially offsetting factors included lower volumes and weak natural gas and NGL prices which resulted in lower contributions in EEP's gas gathering and processing business. In EEP's liquids business, higher tolls on EEP's major liquids pipeline assets were offset by lower volumes on the North Dakota system due to wide crude oil price differentials that made transportation by rail competitive, although tightening crude oil price differentials in the third quarter of 2013 resulted in incremental volumes returning to the North Dakota system. Rail competition is expected to persist as rail provides transportation service to certain markets not currently accessible by pipelines. In the third quarter of 2013, EEP completed hydrostatic testing on Line 14 of its Lakehead System, which also contributed to lower adjusted earnings in EEP's liquids business. Adjusted earnings were also impacted by higher operating and administrative expense, primarily from an increased workforce, and higher depreciation expense associated with new assets placed into service.

Alberta Clipper US earnings decreased for the three and nine months ended September 30, 2013 compared with the corresponding 2012 periods due to a reduction in toll rates, which took effect April 1, 2013, as well as lower throughput. Variations in earnings from the regulated allowed return on rate base are recovered from or refunded to shippers in the following fiscal year.

Earnings for the Fund for the first nine months of 2013 included earnings from crude oil storage and renewable energy assets acquired from Enbridge and its wholly-owned subsidiaries in December 2012.

Earnings were also positively impacted by higher preferred unit distributions received from the Fund, earnings from the Bakken Expansion Program, which commenced operations in March 2013, and lower income taxes. Partially offsetting these sources of earnings growth was higher interest expense as well as a one-time charge recognized in the first quarter of 2013 related to the write-off of a regulatory deferral balance for which recoverability is no longer probable. Refer to *Recent Developments – Sponsored Investments – Enbridge Income Fund – Saskatchewan System Shipper Complaint*.

Sponsored Investment earnings were impacted by the following adjusting items:

- EEP earnings for 2013 and 2012 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Crude Oil Releases.*
- EEP earnings for 2013 and 2012 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Crude Oil Releases.*
- EEP earnings for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- EEP earnings for 2013 included an out-of-period, non-cash deferred income tax adjustment related to a tax law change.
- EEP earnings for 2012 reflected a charge for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.

CORPORATE

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Noverco	**(2)**	(3)	**34**	19
Other Corporate	**(18)**	(14)	**(46)**	(26)
Adjusted loss	**(20)**	(17)	**(12)**	(7)
Noverco - changes in unrealized derivative fair value gains/(loss)	**5**	(11)	**4**	(11)
Noverco - equity earnings adjustment	**-**	-	**-**	(12)
Other Corporate - changes in unrealized derivative fair value gains/(loss)	**77**	89	**(177)**	32
Other Corporate - foreign tax recovery	**-**	-	**4**	29
Other Corporate - unrealized foreign exchange loss on translation of intercompany balances, net	**-**	(17)	**-**	(17)
Other Corporate - tax rate differences/changes	**-**	(4)	**18**	(7)
Earnings/(loss) attributable to common shareholders	**62**	40	**(163)**	7

Adjusted earnings from Noverco reflected results from Noverco's underlying gas and power distribution investments and the Company's preferred share investment. Noverco third quarter of 2013 adjusted earnings were comparable to the corresponding 2012 period and reflected the inherent seasonality of the quarterly earnings profile. Noverco's power distribution business is subject to seasonality, similar to gas distribution operations, with the majority of its annual earnings achieved during the colder months of the year. Adjusted earnings were higher for the nine months ended September 30, 2013 compared with the first nine months of 2012 due to stronger first quarter volumes and contributions from the acquired power distribution assets.

Other Corporate adjusted loss increased for the three and nine months ended September 30, 2013 compared with the corresponding 2012 periods due to higher preference share dividends paid as a result of an increase in the number of preference shares outstanding. Since July 2012, the Company has issued 98 million preference shares for gross proceeds of $2,467 million to provide capital for the Company's current slate of growth projects. See *Recent Developments – Corporate – Preference Share Issuances*. Partially offsetting incremental preference share dividends were lower net Corporate segment finance costs and lower operating and administrative costs.

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

- Noverco earnings/(loss) for each period included changes in the unrealized fair value of derivative financial instruments.
- Noverco loss for 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Other Corporate earnings/(loss) for each period included changes in the unrealized fair value gains and losses of derivative financial instruments related to forward foreign exchange risk management positions.
- Other Corporate earnings/(loss) for 2013 and 2012 was reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate earnings for 2012 included net unrealized foreign exchange loss on the translation of foreign-denominated intercompany balances.
- Other Corporate earnings/(loss) for 2013 and 2012 was impacted by tax rate differences.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility continues to be 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 also maintains a longer horizon funding plan which considers growth capital needs and identifies potential sources of debt and equity funding alternatives, including via its sponsored vehicles, with the objective of maintaining access to low cost capital.

The Company's financing strategy includes optimization of the funding of its enterprise-wide slate of attractive growth projects utilizing its sponsored vehicles. During the first nine months of 2013, several actions were announced to enhance liquidity at EEP during the next several years until its growth capital commitments are permanently funded:

- On May 8, 2013, Enbridge invested US$1.2 billion in preferred units issued by EEP. The preferred units, with a price per unit of $25 (par value), have a fixed yield of 7.5% with the rate to be reset every five years. Under the preferred units terms, quarterly cash distributions will not be payable in cash during the first eight quarters and will be added to the redemption value. Quarterly cash distributions will be payable beginning in the ninth quarter and deferred distributions are payable on the fifth anniversary or when redemption of the units takes place. The preferred units will be redeemable at EEP's option on the five-year anniversary of the issuance and every fifth year thereafter, at par and including the deferred distribution. Earlier redemption is permitted under certain events including the ability to redeem the preferred units using the net proceeds from EEP's equity issuances or from the sale of assets and from the issuance of debt, in equal amounts. In addition, on or after June 1, 2016, at Enbridge's sole option, the preferred units can be converted into approximately 43.2 million common units of EEP.
- On June 28, 2013, EEP exercised the options to reduce its funding and associated economic interest in each of the Eastern Access, excluding the Toledo Expansion and Line 9 Reversal and Expansion, and Lakehead System Mainline Expansion projects by 15% to 25%. EEP retains the option to increase its economic interest back up to 40% in the respective projects within one year of the final project in-service dates.
- Also on June 28, 2013, a wholly-owned subsidiary of Enbridge entered into an agreement with EEP and certain of its subsidiaries to purchase accounts receivable on a monthly basis through 2016, up to a maximum of US$350 million at any one point, which was further amended to a monthly maximum of US$450 million on September 20, 2013.

- On October 31, 2013, MEP, which is currently EEP's wholly-owned subsidiary, launched its initial public offering of 18.5 million Class A common units representing limited partner interests pursuant to the Registration Statement on Form S-1 with the SEC. The Class A common units being offered represent a 40% limited partner interest in MEP, or a 46% limited partner interest if the underwriters exercise, in full, their option to purchase additional Class A common units. EEP, through certain of its subsidiaries, will hold a 2% general partner interest and the remaining limited partner interest in MEP. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Midcoast Energy Partners Initial Public Offering.*

In accordance with its funding plan, the Company completed the following issuances to date in 2013:
- Corporate - $1,217 million in preference shares; $600 million in common shares; $1,888 million of medium-term notes;
- Enbridge Pipelines Inc. (EPI) - $550 million of medium-term notes;
- EEM - US$509 million in listed shares; and
- The Fund - $96 million in common units.

In addition, in June 2013, the Company received dividends of approximately $248 million from its investment in Noverco which resulted from Noverco's sale of Enbridge shares via a secondary offering.

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge also has a significant amount of committed bank credit facilities which were further bolstered in the third quarter of 2013, as the Company increased its enterprise-wide general purpose credit facilities to $16 billion.

The Company's net available liquidity of $12,214 million at September 30, 2013 was inclusive of approximately $276 million of unrestricted cash and cash equivalents, net of bank indebtedness. In addition to ensuring adequate liquidity, the Company actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company's credit facilities at September 30, 2013 and December 31, 2012.

		September 30, 2013			December 31, 2012
	Maturity Dates[2]	Total Facilities	Draws[3]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**26**	**274**	300
Gas Distribution	2014-2015	**712**	**604**	**108**	712
Sponsored Investments[4]	2015-2018	**3,791**	**571**	**3,220**	3,162
Corporate[4]	2015-2018	**11,218**	**2,882**	**8,336**	9,108
		16,021	**4,083**	**11,938**	13,282
Southern Lights project financing[1]	2014-2015	**1,530**	**1,460**	**70**	1,484
Total credit facilities		**17,551**	**5,543**	**12,008**	14,766

1 Total facilities inclusive of $61 million for debt service reserve letters of credit.
2 Total facilities include $35 million in demand facilities with no specified maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.
4 In October 2013, the Company extended the maturity dates of a US$2.0 billion facility from 2017 to 2018 in the Sponsored Investments segment and of a US$1.5 billion facility from 2014 to 2015 in the Corporate segment.

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 $23 million for specific shipper commitments.

OPERATING ACTIVITIES

Cash provided by operating activities was $830 million and $2,560 million for the three and nine months ended September 30, 2013, respectively, compared with $740 million and $2,372 million for the three and nine months ended September 30, 2012.

The increase in cash flows provided by operating activities for the nine months ended September 30, 2013 compared with the corresponding period of 2012 was primarily due to cash growth delivered by operations. As discussed in *Financial Results*, the Company experienced higher earnings mainly from higher volumes and new assets in Liquids Pipelines, better arbitrage opportunities in Energy Services and stronger contributions from EEP and the Fund which increased the period-over-period cash flows. Partially offsetting these increases was a lower dividend paid by Noverco in 2013 compared with 2012. In the second quarter of 2013, Noverco paid a one-time dividend of $248 million (2012 - $317 million) upon realization of a substantial gain on the disposition of a portion of its investment in Enbridge shares.

The third quarter of 2013 experienced similar trends as the nine months ended September 30, 2013; however, the third quarter cash flows were partially impacted by a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll in Liquids Pipelines. In addition, the third quarter cash flows were also impacted by a favourable variance in changes in operating assets and liabilities of $169 million. Operating assets and liabilities will fluctuate from time to time due to inventory levels, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company's businesses.

INVESTING ACTIVITIES

Cash used in investing activities for the three and nine months ended September 30, 2013 was $2,562 million and $6,154 million, respectively, compared with $1,619 million and $4,022 million for the three and nine months ended September 30, 2012. Cash usage for investing activities for the three and nine months ended September 30, 2013 increased mainly due to additions to property, plant and equipment for the construction of the Company's growth projects and funding of various investments and joint ventures, primarily the Texas Express NGL System and Seaway Pipeline.

FINANCING ACTIVITIES

For the three and nine months ended September 30, 2013, cash generated from financing activities was $1,175 million and $2,326 million, respectively, compared with $1,949 million and $2,670 million for the three and nine months ended September 30, 2012.

In the first nine months of 2013, the Company's overall debt increased by $944 million compared with a net increase of $423 million for the comparative period. Contributions, net of distributions, received primarily from third party investors in EEM and EEP of $175 million (2012 - $136 million) and from the Fund's public unitholders of $37 million (2012 - $35 million net distributions) also contributed to an increase in cash generated from financing activities compared with the first nine months of 2012. The net proceeds from the issuance of common shares was $616 million for the first three quarters of 2013 (2012 - $419 million). These increases in sources of cash flow were more than offset by lower preference share issuances in 2013. The Company raised net proceeds of $1,186 million in the nine month period ended September 30, 2013 from the issuance of preference shares compared with $2,245 million raised in the comparative period.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended September 30, 2013, dividends declared were $261 million (2012 - $225 million), of which $167 million (2012 - $150 million) were paid in cash and reflected in financing activities. The remaining $94 million (2012 - $75 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the nine months ended September 30, 2013, dividends declared were $774 million (2012 - $668 million), of which $504 million (2012 - $455 million) were paid in cash and reflected in financing activities. The remaining $270 million (2012 - $213 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and nine months ended September 30, 2013, 36% (2012 - 33%) and 35% (2012 - 32%), respectively, of total dividends declared were reinvested.

On October 30, 2013, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2013 to shareholders of record on November 15, 2013.

Common Shares	$0.31500
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[1]	US$0.19590

1 *This first dividend declared for the Preference Shares, Series 5 includes accrued dividends from September 27, 2013, the date the shares were issued. The regular quarterly dividend of US$0.275 per share will take effect on March 1, 2014. See* Recent Developments – Corporate – Preference Share Issuances.

Capital Expenditure Commitments
At September 30, 2013, the Company had approximately $4,712 million in outstanding purchase commitments attributable to the construction of assets that are expected to be recorded as property, plant and equipment within the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE 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 price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price 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 2018 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 $10,558 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.7%.

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 September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(18)**	(28)	**29**	(19)
Interest rate contracts	**(86)**	(1)	**703**	(190)
Commodity contracts	**(23)**	(27)	**(6)**	54
Other contracts	**(3)**	(3)	**(4)**	(3)
Net investment hedges				
Foreign exchange contracts	**25**	34	**(42)**	16
	(105)	(25)	**680**	(142)
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(2)**	2	**(5)**	1
Interest rate contracts[2]	**43**	(7)	**89**	17
Commodity contracts[3]	**5**	-	**1**	(3)
	46	(5)	**85**	15
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**1**	(1)	**24**	3
Commodity contracts[3]	**-**	4	**(2)**	(1)
	1	3	**22**	2
Amount of gains/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**319**	303	**(382)**	242
Interest rate contracts[2]	**(2)**	(1)	**(7)**	(2)
Commodity contracts[3]	**20**	(531)	**124**	(973)
Other contracts[4]	**(1)**	(2)	**3**	3
	336	(231)	**(262)**	(730)

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

LIQUIDITY RISK
Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments, 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 one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at September 30, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

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

The Company generally has a policy of entering into International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with 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
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 EPI and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc. and Vector Pipelines Limited Partnership (Group 2 companies). In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies and issued its decision on February 14, 2013. The outcome does not materially impact tolls. On February 28, 2013, Group 1 companies filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies filed collection mechanism applications and the Group 2 companies filed both their set-aside and collection mechanism applications. Once the set-aside and collection mechanism is approved by the NEB, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The collections are expected to begin in 2015.

All applications by the Company will require NEB approval. The NEB has set a hearing, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. The hearing is to commence January 14, 2014 with the decision expected in the second quarter of 2014.

Currently, for certain 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 asset retirement obligation (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.

CHANGES IN ACCOUNTING POLICIES

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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

ADOPTION OF NEW STANDARDS

Balance Sheet Offsetting

Effective January 1, 2013, the Company adopted Accounting Standards Update (ASU) 2011-11 and ASU 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Company's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Company adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of AOCI. As the adoption of this update impacted disclosure only, there was no impact to the Company's consolidated financial statements for the current or prior periods presented.

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. 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, 2013 and is to be applied retrospectively.

Parent's Accounting for the Cumulative Translation Adjustment

ASU 2013-05 was issued in March 2013 and 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. 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, 2013 and is to be applied prospectively.

Presentation of Unrecognized Tax Benefits

ASU 2013-11 was issued in July 2013 and provides guidance on presenting unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. 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, 2013 and is to be applied prospectively.

QUARTERLY FINANCIAL INFORMATION

	2013			2012[1]				2011[1]
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
(millions of Canadian dollars, except per share amounts)								
Revenues	**8,998**	7,730	7,897	7,039	5,676	5,445	6,532	7,244
Earnings attributable to common shareholders	**421**	42	250	146	187	8	261	155
Earnings per common share	**0.52**	0.05	0.32	0.19	0.24	0.01	0.34	0.21
Diluted earnings per common share	**0.51**	0.05	0.31	0.18	0.24	0.01	0.34	0.20
Dividends per common share	**0.3150**	0.3150	0.3150	0.2825	0.2825	0.2825	0.2825	0.2450
EGD - warmer/(colder) than normal weather	**-**	(2)	6	(1)	-	-	24	12
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**(223)**	246	207	81	93	252	110	(241)

1 *Revenues, Earnings attributable to common shareholders, Earnings per common share and Diluted earnings per common share for the 2012 and 2011 comparative periods have been revised. See Note 2 to the September 30, 2013 Consolidated Financial Statements.*

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. Gas Distribution's earnings for the fourth quarter of 2011 included an extraordinary charge totaling $262 million, after-tax, as a result of the discontinuance of rate-regulated accounting at EGNB and the related write-off of a deferred regulatory asset and certain capitalized operating costs.

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

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

- Included in earnings are after-tax costs of $40 million and $13 million incurred respectively in the second and third quarters of 2013, in connection with the Line 37 crude oil release. Included in the second quarter costs were expenditures of approximately $15 million after-tax to ensure long-term stability of Line 37 and other lines within the right-of-way.
- Included in earnings is the Company's share of leak remediation costs associated with the Lines 6A, 6B and 14 crude oil releases. Remediation costs and lost revenues of $24 million and $6 million were recognized in the first quarter and second quarters of 2013; $2 million and $7 million in the second and third quarter of 2012; and $6 million in the fourth quarter of 2011, respectively. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013, $24 million in the third quarter of 2012 and $29 million in the fourth quarter of 2011, respectively.

- In the fourth quarter of 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors. Also included in the fourth quarter of 2012 was a $63 million after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.
- Fourth quarter earnings for 2012 and 2011 were also impacted by the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million and $98 million, respectively, incurred on the related capital gains.

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 anticipated construction commencement and in-service dates, are described in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development.*

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Earnings attributable to common shareholders	**421**	187	**713**	456
Adjusting items:				
Liquids Pipelines				
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**(133)**	(90)	**125**	(83)
Canadian Mainline - Line 9 tolling adjustment	**-**	-	**-**	(6)
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**13**	-	**53**	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**37**	-	**37**	-
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**(31)**	-	**(31)**	-
Spearhead Pipeline - changes in unrealized derivative fair value loss[1]	**-**	1	**-**	-
Gas Distribution				
EGD - gas transportation costs out-of-period adjustment	**56**	-	**56**	-
EGD - warmer than normal weather	**-**	-	**4**	24
EGD - tax rate changes	**-**	-	**-**	9
Gas Pipelines, Processing and Energy Services				
Aux Sable - changes in unrealized derivative fair value (gains)/loss[1]	**-**	8	**-**	(15)
Energy Services - changes in unrealized derivative fair value (gains)/loss[1]	**(18)**	232	**(131)**	558
Other - changes in unrealized derivative fair value (gains)/loss[1]	**4**	(3)	**60**	-
Sponsored Investments				
EEP - leak insurance recoveries	**-**	(24)	**(6)**	(24)
EEP - leak remediation costs	**5**	7	**35**	9
EEP - changes in unrealized derivative fair value (gains)/loss[1]	**6**	6	**3**	(1)
EEP - tax rate differences/changes	**-**	-	**3**	-
EEP - NGL trucking and marketing investigation costs	**-**	-	**-**	1
Corporate				
Noverco - changes in unrealized derivative fair value (gains)/loss[1]	**(5)**	11	**(4)**	11
Noverco - equity earnings adjustment	**-**	-	**-**	12
Other Corporate - changes in unrealized derivative fair value (gains)/loss[1]	**(77)**	(89)	**177**	(32)
Other Corporate - foreign tax recovery	**-**	-	**(4)**	(29)
Other Corporate - unrealized foreign exchange loss on translation of intercompany balances, net	**-**	17	**-**	17
Other Corporate - tax rate differences/changes	**-**	4	**(18)**	7
Adjusted earnings	**278**	267	**1,072**	914

1 *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.*

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
Common Shares - issued and outstanding (voting equity shares)	828,170,125
Stock Options - issued and outstanding (16,885,791 vested)	34,922,095

1 *Outstanding share data information is provided as at October 25, 2013.*

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.*

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**7,141**	4,538	**19,100**	13,516
Gas distribution sales	**270**	230	**1,555**	1,325
Transportation and other services	**1,587**	908	**3,970**	2,812
	8,998	5,676	**24,625**	17,653
Expenses				
Commodity costs	**6,981**	4,363	**18,449**	12,962
Gas distribution costs	**217**	79	**1,095**	779
Operating and administrative	**766**	724	**2,226**	2,037
Depreciation and amortization	**352**	301	**1,008**	911
Environmental costs, net of recoveries *(Note 14)*	**41**	(132)	**280**	(106)
	8,357	5,335	**23,058**	16,583
	641	341	**1,567**	1,070
Income from equity investments	**79**	40	**244**	129
Other income/(expense)	**164**	147	**(53)**	202
Interest expense	**(223)**	(200)	**(682)**	(630)
	661	328	**1,076**	771
Income taxes *(Note 12)*	**(236)**	(2)	**(339)**	(13)
Earnings	**425**	326	**737**	758
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**45**	(108)	**107**	(233)
Earnings attributable to Enbridge Inc.	**470**	218	**844**	525
Preference share dividends	**(49)**	(31)	**(131)**	(69)
Earnings attributable to Enbridge Inc. common shareholders	**421**	187	**713**	456
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*	**0.52**	0.24	**0.89**	0.59
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*	**0.51**	0.24	**0.88**	0.59

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(unaudited; millions of Canadian dollars)				
Earnings	**425**	326	**737**	758
Other comprehensive income/(loss), net of tax				
Change in unrealized gains/(loss) on cash flow hedges	**(44)**	(96)	**540**	(224)
Change in unrealized gains/(loss) on net investment hedges	**34**	46	**(40)**	28
Other comprehensive income from equity investees	**6**	4	**12**	3
Reclassification to earnings of realized cash flow hedges	**31**	(2)	**66**	17
Reclassification to earnings of unrealized cash flow hedges	**2**	3	**17**	2
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**5**	7	**22**	14
Change in foreign currency translation adjustment	**(241)**	(292)	**288**	(259)
Other comprehensive income/(loss)	**(207)**	(330)	**905**	(419)
Comprehensive income/(loss)	**218**	(4)	**1,642**	339
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**122**	19	**(134)**	(108)
Comprehensive income attributable to Enbridge Inc.	**340**	15	**1,508**	231
Preference share dividends	**(49)**	(31)	**(131)**	(69)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**291**	(16)	**1,377**	162

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Nine months ended September 30,	
	2013	2012
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 8)*		
Balance at beginning of period	**3,707**	1,056
Preference shares issued	**1,189**	2,260
Balance at end of period	**4,896**	3,316
Common shares		
Balance at beginning of period	**4,732**	3,969
Shares issued	**586**	388
Dividend reinvestment and share purchase plan	**270**	213
Shares issued on exercise of stock options	**54**	39
Balance at end of period	**5,642**	4,609
Additional paid-in capital		
Balance at beginning of period	**522**	242
Stock-based compensation	**24**	21
Options exercised	**(14)**	(9)
Issuance of treasury stock	**208**	236
Dilution gains and other	**4**	7
Balance at end of period	**744**	497
Retained earnings		
Balance at beginning of period	**3,173**	3,642
Earnings attributable to Enbridge Inc.	**844**	525
Preference share dividends	**(131)**	(69)
Common share dividends declared	**(774)**	(668)
Dividends paid to reciprocal shareholder	**15**	14
Redemption value adjustment attributable to redeemable noncontrolling interests	**(32)**	(123)
Balance at end of period	**3,095**	3,321
Accumulated other comprehensive loss *(Note 9)*		
Balance at beginning of period	**(1,762)**	(1,496)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**664**	(294)
Balance at end of period	**(1,098)**	(1,790)
Reciprocal shareholding		
Balance at beginning of period	**(126)**	(187)
Issuance of treasury stock	**40**	61
Balance at end of period	**(86)**	(126)
Total Enbridge Inc. shareholders' equity	**13,193**	9,827
Noncontrolling interests		
Balance at beginning of period	**3,258**	3,141
Earnings/(loss) attributable to noncontrolling interests	**(87)**	238
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**131**	(27)
Change in foreign currency translation adjustment	**105**	(101)
Reclassification to earnings of realized cash flow hedges	**3**	5
Reclassification to earnings of unrealized cash flow hedges	**(1)**	(1)
	238	(124)
Comprehensive income attributable to noncontrolling interests	**151**	114
Contributions	**523**	377
Distributions	**(348)**	(305)
Acquisitions	**-**	(25)
Other	**1**	1
Balance at end of period	**3,585**	3,303
Total equity	**16,778**	13,130
Dividends paid per common share	**0.9450**	0.8475

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**425**	326	**737**	758
Depreciation and amortization	**352**	301	**1,008**	911
Changes in unrealized (gains)/loss on derivative instruments	**(332)**	217	**274**	748
Cash distributions in excess of equity earnings	**105**	23	**316**	410
Deferred income taxes (recovery)/expense	**294**	25	**365**	(60)
Other	**(58)**	(5)	**7**	42
Changes in regulatory assets and liabilities	**(6)**	9	**14**	35
Changes in environmental liabilities, net of recoveries *(Note 14)*	**-**	(37)	**201**	(46)
Changes in operating assets and liabilities	**50**	(119)	**(362)**	(426)
	830	740	**2,560**	2,372
Investing activities				
Additions to property, plant and equipment	**(2,229)**	(1,408)	**(5,285)**	(3,407)
Long-term investments	**(303)**	(168)	**(726)**	(259)
Additions to intangible assets	**(26)**	(46)	**(137)**	(130)
Acquisition	**-**	-	**-**	(221)
Affiliate loans, net	**2**	1	**5**	4
Changes in restricted cash	**(6)**	2	**(11)**	(9)
	(2,562)	(1,619)	**(6,154)**	(4,022)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**(371)**	391	**(225)**	285
Net change in commercial paper and credit facility draws	**223**	225	**352**	(692)
Net change in Southern Lights project financing	**-**	6	**(5)**	(13)
Debenture and term note issues	**1,232**	499	**1,232**	999
Debenture and term note repayments	**-**	(156)	**(410)**	(156)
Contributions from noncontrolling interests	**243**	438	**523**	441
Distributions to noncontrolling interests	**(120)**	(100)	**(348)**	(305)
Contributions from redeemable noncontrolling interests	**-**	-	**91**	-
Distributions to redeemable noncontrolling interests	**(18)**	(12)	**(54)**	(35)
Preference shares issued	**200**	827	**1,186**	2,245
Common shares issued	**2**	10	**616**	419
Preference share dividends	**(49)**	(29)	**(128)**	(63)
Common share dividends	**(167)**	(150)	**(504)**	(455)
	1,175	1,949	**2,326**	2,670
Effect of translation of foreign denominated cash and cash equivalents	**(4)**	(11)	**8**	(17)
Increase/(decrease) in cash and cash equivalents	**(561)**	1,059	**(1,260)**	1,003
Cash and cash equivalents at beginning of period	**1,077**	667	**1,776**	723
Cash and cash equivalents at end of period	**516**	1,726	**516**	1,726

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited; millions of Canadian dollars; number of shares in millions)	**September 30, 2013**	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	**516**	1,776
Restricted cash	**30**	19
Accounts receivable and other *(Note 5)*	**4,471**	4,014
Accounts receivable from affiliates	**15**	12
Inventory	**1,239**	779
	6,271	6,600
Property, plant and equipment, net	**38,889**	33,318
Long-term investments *(Note 6)*	**3,845**	3,175
Deferred amounts and other assets	**2,758**	2,461
Intangible assets, net	**915**	817
Goodwill	**432**	419
Deferred income taxes	**8**	10
	53,118	46,800
Liabilities and equity		
Current liabilities		
Bank indebtedness	**240**	479
Short-term borrowings	**597**	583
Accounts payable and other	**5,841**	5,052
Interest payable	**233**	196
Environmental liabilities	**294**	107
Current maturities of long-term debt	**2,507**	652
	9,712	7,069
Long-term debt	**19,799**	20,203
Other long-term liabilities	**2,806**	2,541
Deferred income taxes	**2,971**	2,483
	35,288	32,296
Contingencies *(Note 14)*		
Redeemable noncontrolling interests	**1,052**	1,000
Equity		
Share capital		
Preference shares *(Note 8)*	**4,896**	3,707
Common shares (828 and 805 outstanding at September 30, 2013 and December 31, 2012, respectively)	**5,642**	4,732
Additional paid-in capital	**744**	522
Retained earnings	**3,095**	3,173
Accumulated other comprehensive loss *(Note 9)*	**(1,098)**	(1,762)
Reciprocal shareholding *(Note 10)*	**(86)**	(126)
Total Enbridge Inc. shareholders' equity	**13,193**	10,246
Noncontrolling interests	**3,585**	3,258
	16,778	13,504
	53,118	46,800

See accompanying notes to the unaudited interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2012. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments with the exception of certain out-of-period adjustments further described in Note 4, Segmented Information, which management considers necessary to present fairly the Company's financial position as at September 30, 2013 and results of operations and cash flows for the three and nine months ended September 30, 2013 and 2012. 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, 2012, except for the adoption of new standards *(Note 3)*. 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. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Company's consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Company recorded deferred regulatory assets associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls for certain of its regulated operations. Further, to the extent the deferred regulatory asset gave rise to temporary differences, an offsetting regulatory asset with respect to deferred income taxes was also recognized. During the three months ended September 30, 2013, the Company identified that certain intercompany commodity sales and commodity purchase transactions within Energy Services were not appropriately eliminated upon consolidation. This presentation matter had no effect on the margin, earnings or cash flows for any prior period.

In accordance with accounting guidance found in Accounting Standards Codification (ASC) 250-10 (Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 99, *Materiality*), the Company assessed the materiality of these errors and concluded that they were not material to any of the Company's previously issued consolidated financial statements. In accordance with guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*), the Company will revise its comparative consolidated financial statements to correct the effects of these matters. These non-cash revisions do not impact cash flows for any prior period.

The following tables present the effect of these corrections on individual line items within the Company's Consolidated Statements of Earnings and Consolidated Statements of Financial Position. The effects which flow through to the individual line items of Earnings, Depreciation and amortization, Cash distributions in excess of equity earnings, Deferred income taxes, Changes in regulatory assets and liabilities and Changes in operating assets and liabilities of the Consolidated Statements of Cash Flows are not significant and have no net effect on the Company's cash flows from operating activities.

	Three months ended September 30, 2012			Three months ended September 30, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars, except per share amounts)						
Commodity sales	4,648	(110)	4,538	5,159	(61)	5,098
Transportation and other services revenues	910	(2)	908	888	(2)	886
Commodity costs	4,473	(110)	4,363	4,959	(61)	4,898
Depreciation and amortization	293	8	301	272	10	282
Income from equity investments	32	8	40	31	6	37
Income taxes recovery/(expense)	(2)	-	(2)	24	1	25
Earnings	328	(2)	326	58	(5)	53
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(108)	-	(108)	(62)	-	(62)
Earnings attributable to Enbridge Inc.	220	(2)	218	(4)	(5)	(9)
Earnings attributable to Enbridge Inc. common shareholders	189	(2)	187	(5)	(5)	(10)
Earnings per common share attributable to Enbridge Inc. common shareholders	0.24	-	0.24	(0.01)	-	(0.01)
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.24	-	0.24	(0.01)	-	(0.01)

	Nine months ended September 30, 2012			Nine months ended September 30, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars, except per share amounts)						
Commodity sales	13,990	(474)	13,516	15,416	(173)	15,243
Transportation and other services revenues	2,818	(6)	2,812	2,990	(7)	2,983
Commodity costs	13,436	(474)	12,962	14,835	(173)	14,662
Depreciation and amortization	883	28	911	823	31	854
Income from equity investments	104	25	129	140	18	158
Income taxes expense	(14)	1	(13)	(223)	4	(219)
Earnings	766	(8)	758	891	(16)	875
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(233)	-	(233)	(225)	1	(224)
Earnings attributable to Enbridge Inc.	533	(8)	525	666	(15)	651
Earnings attributable to Enbridge Inc. common shareholders	464	(8)	456	661	(15)	646
Earnings per common share attributable to Enbridge Inc. common shareholders	0.60	(0.01)	0.59	0.88	(0.02)	0.86
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.59	-	0.59	0.87	(0.02)	0.85

	Year ended December 31, 2012			Year ended December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars, except per share amounts)						
Commodity sales	19,101	(607)	18,494	20,611	(237)	20,374
Transportation and other services revenues	4,295	(7)	4,288	4,536	(8)	4,528
Commodity costs	18,566	(607)	17,959	19,864	(237)	19,627
Depreciation and amortization	1,206	36	1,242	1,112	42	1,154
Income from equity investments	160	35	195	210	23	233
Income taxes expense	(128)	1	(127)	(526)	6	(520)
Earnings	943	(7)	936	1,242	(21)	1,221
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(228)	(1)	(229)	(409)	2	(407)
Earnings attributable to Enbridge Inc.	715	(8)	707	833	(19)	814
Earnings attributable to Enbridge Inc. common shareholders	610	(8)	602	820	(19)	801
Earnings per common share attributable to Enbridge Inc. common shareholders	0.79	(0.01)	0.78	1.09	(0.02)	1.07
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.78	(0.01)	0.77	1.08	(0.03)	1.05

	Year ended December 31, 2010		
	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars, except per share amounts)			
Commodity sales	15,863	(132)	15,731
Transportation and other services revenues	3,843	(4)	3,839
Commodity costs	15,276	(132)	15,144
Depreciation and amortization	1,017	22	1,039
Income from equity investments	228	4	232
Income taxes expense	(227)	4	(223)
Earnings	781	(18)	763
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	170	4	174
Earnings attributable to Enbridge Inc.	951	(14)	937
Earnings attributable to Enbridge Inc. common shareholders	944	(14)	930
Earnings per common share attributable to Enbridge Inc. common shareholders	1.27	(0.01)	1.26
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	1.26	(0.02)	1.24

In addition, the Company has downwardly revised both Commodity sales and Commodity costs by $120 million for the three months ended March 31, 2013 and $117 million and $237 million for the three and six months ended June 30, 2013, respectively.

	As at December 31, 2012			As at December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars)						
Long-term investments	3,386	(211)	3,175	3,081	(248)	2,833
Deferred amounts and other assets	2,622	(161)	2,461	2,500	(116)	2,384
Deferred income tax liabilities	2,601	(118)	2,483	2,615	(116)	2,499
Retained earnings	3,464	(291)	3,173	3,926	(284)	3,642
Accumulated other comprehensive loss	(1,799)	37	(1,762)	(1,532)	36	(1,496)

3. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Balance Sheet Offsetting

Effective January 1, 2013, the Company adopted Accounting Standards Update (ASU) 2011-11 and ASU 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Company's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Company adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of Accumulated other comprehensive income/(loss) (AOCI). As the adoption of this update impacted disclosure only, there was no impact to the Company's consolidated financial statements for the current or prior periods presented.

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. 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, 2013 and is to be applied retrospectively.

Parent's Accounting for the Cumulative Translation Adjustment

ASU 2013-05 was issued in March 2013 and 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. 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, 2013 and is to be applied prospectively.

Presentation of Unrecognized Tax Benefits

ASU 2013-11 was issued in July 2013 and provides guidance on presenting unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. 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, 2013 and is to be applied prospectively.

4. SEGMENTED INFORMATION

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

Three months ended September 30, 2012	Liquids Pipelines[2]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3]	Sponsored Investments[2]	Corporate[1,3]	Consolidated
(millions of Canadian dollars)						
Revenues	746	312	3,075	1,543	-	5,676
Commodity and gas distribution costs	-	(79)	(3,375)	(988)	-	(4,442)
Operating and administrative	(259)	(133)	(41)	(276)	(15)	(724)
Depreciation and amortization	(95)	(82)	(17)	(104)	(3)	(301)
Environmental costs, net of recoveries	-	-	-	132	-	132
	392	18	(358)	307	(18)	341
Income/(loss) from equity investments	19	-	36	13	(28)	40
Other income/(expense)	8	(3)	12	13	117	147
Interest income/(expense)	(65)	(41)	(9)	(97)	12	(200)
Income taxes recovery/(expense)	(77)	8	128	(49)	(12)	(2)
Earnings/(loss)	277	(18)	(191)	187	71	326
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	(107)	-	(108)
Preference share dividends	-	-	-	-	(31)	(31)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	276	(18)	(191)	80	40	187
Additions to property, plant and equipment[4]	469	111	182	577	70	1,409

Nine months ended September 30, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**1,780**	**1,900**	**15,484**	**5,461**	**-**	**24,625**
Commodity and gas distribution costs	**-**	**(1,095)**	**(14,895)**	**(3,554)**	**-**	**(19,544)**
Operating and administrative	**(726)**	**(400)**	**(204)**	**(895)**	**(1)**	**(2,226)**
Depreciation and amortization	**(315)**	**(237)**	**(52)**	**(391)**	**(13)**	**(1,008)**
Environmental costs, net of recoveries	**(68)**	**-**	**-**	**(212)**	**-**	**(280)**
	671	**168**	**333**	**409**	**(14)**	**1,567**
Income from equity investments	**89**	**-**	**109**	**41**	**5**	**244**
Other income/(expense)	**29**	**12**	**32**	**10**	**(136)**	**(53)**
Interest income/(expense)	**(234)**	**(118)**	**(58)**	**(285)**	**13**	**(682)**
Income taxes recovery/(expense)	**(171)**	**(13)**	**(159)**	**(96)**	**100**	**(339)**
Earnings/(loss)	**384**	**49**	**257**	**79**	**(32)**	**737**
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(3)**	**-**	**-**	**110**	**-**	**107**
Preference share dividends	**-**	**-**	**-**	**-**	**(131)**	**(131)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**381**	**49**	**257**	**189**	**(163)**	**713**
Additions to property, plant and equipment[4]	**2,690**	**360**	**591**	**1,625**	**20**	**5,286**

Nine months ended September 30, 2012	Liquids Pipelines[2]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3]	Sponsored Investments[2]	Corporate[1,3]	Consolidated
(millions of Canadian dollars)						
Revenues	1,865	1,658	9,239	4,891	-	17,653
Commodity and gas distribution costs	-	(779)	(9,873)	(3,089)	-	(13,741)
Operating and administrative	(714)	(389)	(117)	(795)	(22)	(2,037)
Depreciation and amortization	(286)	(249)	(50)	(317)	(9)	(911)
Environmental costs, net of recoveries	-	-	-	106	-	106
	865	241	(801)	796	(31)	1,070
Income/(loss) from equity investments	26	-	107	40	(44)	129
Other income/(expense)	25	(4)	34	36	111	202
Interest income/(expense)	(193)	(122)	(33)	(291)	9	(630)
Income taxes recovery/(expense)	(153)	(35)	285	(141)	31	(13)
Earnings/(loss)	570	80	(408)	440	76	758
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	-	(1)	(229)	-	(233)
Preference share dividends	-	-	-	-	(69)	(69)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	567	80	(409)	211	7	456
Additions to property, plant and equipment[4]	1,252	316	554	1,222	64	3,408

1 *Included within the Corporate segment was Interest income of $121 million and $314 million for the three and nine months ended September 30, 2013, respectively, (2012 - $88 million and $252 million, respectively) charged to other operating segments.*

2 *In December 2012, certain crude oil storage and renewable energy assets were transferred to Enbridge Income Fund within the Sponsored Investments segment. Earnings from the assets for the three and nine months ended September 30, 2012 of $8 million and $26 million, respectively, have not been reclassified among segments for presentation purposes.*

3 *Due to a change in organizational structure, effective January 1, 2013, earnings of $4 million and $1 million for the three and nine months ended September 30, 2013 and additions to property, plant and equipment of $16 million and $74 million for the three and nine months ended September 30, 2013, respectively, were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.*

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

OUT-OF-PERIOD ADJUSTMENTS

Earnings attributable to Enbridge Inc. common shareholders for the three months ended September 30, 2013 were reduced by net out-of-period adjustments of $77 million. The adjustment attributable to the Liquids Pipelines segment was a net decrease to earnings of $6 million. Of this net adjustment, $37 million related to a non-cash adjustment to defer revenues associated with make-up rights created pursuant to certain long-term take-or-pay contracts that have more than a remote chance of being utilized. Make-up rights are created when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset the cost of shipping volumes in excess of minimum commitments in future periods, subject to expiry periods. The Liquids Pipelines adjustment also included a net increase to earnings of $31 million related to the recovery of income taxes under a long-term contract, partially offset by a correction to deferred income tax expense. The adjustment attributable to the Gas Distribution segment was $71 million and represented an increase to gas transportation costs which had incorrectly been deferred.

These out-of-period adjustments increased Transportation and other services revenue, Gas distribution costs and Income taxes by $102 million, $98 million and $83 million, respectively.

TOTAL ASSETS

	September 30, 2013	December 31, 2012
(millions of Canadian dollars)		
Liquids Pipelines	**18,747**	15,124
Gas Distribution	**7,596**	7,416
Gas Pipelines, Processing and Energy Services[1]	**6,598**	5,349
Sponsored Investments	**16,963**	15,648
Corporate[1]	**3,214**	3,263
	53,118	46,800

1 At December 31, 2012, total assets of $342 million were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment as a result of a change in organizational structure.

5. ACCOUNTS RECEIVABLE AND OTHER

For the three and nine months ended September 30, 2013, pursuant to a Receivables Purchase Agreement (the Receivables Agreement), certain trade and accrued receivables (the Receivables) have been sold by certain of Enbridge Energy Partners, L.P.'s (EEP) subsidiaries to a wholly-owned special purpose entity (SPE). The Receivables owned by SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement, as amended on September 20, 2013, provides for subsequent purchases to occur on a monthly basis through to December 2016; however, the accumulated purchases net of collections cannot exceed US$450 million at any one point. As at September 30, 2013, the value of trade and accrued receivables outstanding owned by the SPE totaled $413 million.

6. LONG-TERM INVESTMENTS

On April 5, 2013, the Company invested $107 million to acquire a 50% interest in Blackspring Ridge Wind Project (Blackspring Ridge), a wind energy project. The project is currently in the late stage of development. The Company's interest in Blackspring Ridge is included in the Gas Pipelines, Processing and Energy Services segment and was initially accounted for as a long-term equity investment. Effective August 2, 2013, the Company legally restructured its holding to an undivided interest for which Enbridge's proportional ownership is recorded as Property, plant and equipment.

7. CREDIT FACILITIES

September 30, 2013	Maturity Dates[2]	Total Facilities	Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2015	**300**	**26**	**274**
Gas Distribution	2014-2015	**712**	**604**	**108**
Sponsored Investments[4]	2015-2018	**3,791**	**571**	**3,220**
Corporate[4]	2015-2018	**11,218**	**2,882**	**8,336**
		16,021	**4,083**	**11,938**
Southern Lights project financing[1]	2014-2015	**1,530**	**1,460**	**70**
Total credit facilities		**17,551**	**5,543**	**12,008**

1 Total facilities inclusive of $61 million for debt service reserve letters of credit.
2 Total facilities include $35 million in demand facilities with no maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.
4 In October 2013, the Company extended the maturity dates of a US$2.0 billion facility from 2017 to 2018 in the Sponsored Investments segment and of a US$1.5 billion facility from 2014 to 2015 in the Corporate segment.

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 2018.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,322 million (December 31, 2012 - $2,925 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

8. SHARE CAPITAL

PREFERENCE SHARES

	September 30, 2013		December 31, 2012	
	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**	-	-
Preference Shares, Series 3	**24**	**600**	-	-
Preference Shares, Series 5	**8**	**206**	-	-
Issuance costs		**(106)**		(78)
Balance at end of period		**4,896**		3,707

Characteristics of the preference shares are as follows:

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

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) or 2.4% (Series 4)); 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 US$0.1959 per share will be payable on December 1, 2013 to Series 5 shareholders. The regular quarterly dividend of US$0.275 per share will begin in the first quarter of 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 and 16 million (2012 - 18 million and 21 million) for the three and nine months ended September 30, 2013, resulting from the Company's reciprocal investment in Noverco Inc. (Noverco).

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(number of shares in millions)				
Weighted average shares outstanding	**814**	780	**803**	769
Effect of dilutive options	**10**	12	**11**	12
Diluted weighted average shares outstanding	**824**	792	**814**	781

For both the three and nine months ended September 30, 2013, 6,327,500 anti-dilutive stock options (2012 - nil and 3,542,500 for the three and nine months ended September 30, respectively) with a weighted average exercise price of $44.85 (2012 - nil and $39.34 for the three and nine months ended September 30, respectively) were excluded from the diluted earnings per common share calculation.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the nine months ended September 30, 2013 and 2012 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	**(621)**	**474**	**(1,265)**	**(26)**	**(324)**	**(1,762)**
Other comprehensive income/(loss) retained in AOCI	**557**	**(46)**	**183**	**12**	**-**	**706**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**107**	**-**	**-**	**-**	**-**	**107**
Foreign exchange contracts[3]	**(5)**	**-**	**-**	**-**	**-**	**(5)**
Amortization of pension and OPEB actuarial loss and prior service costs[4]	**-**	**-**	**-**	**-**	**29**	**29**
	659	**(46)**	**183**	**12**	**29**	**837**
Tax impact						
Income tax on amounts retained in AOCI	**(147)**	**6**	**-**	**-**	**-**	**(141)**
Income tax on amounts reclassified to earnings	**(25)**	**-**	**-**	**-**	**(7)**	**(32)**
	(172)	**6**	**-**	**-**	**(7)**	**(173)**
Balance at September 30, 2013	**(134)**	**434**	**(1,082)**	**(14)**	**(302)**	**(1,098)**

	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, 2012	(476)	461	(1,167)	(28)	(286)	(1,496)
Other comprehensive income/(loss) retained in AOCI	(250)	32	(158)	8	-	(368)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	10	-	-	-	-	10
Commodity contracts[2]	(3)	-	-	-	-	(3)
Foreign exchange contracts[3]	1	-	-	-	-	1
Amortization of pension and OPEB actuarial loss and prior service costs [4]	-	-	-	-	19	19
	(242)	32	(158)	8	19	(341)
Tax impact						
Income tax on amounts retained in AOCI	57	(4)	-	(5)	-	48
Income tax on amounts reclassified to earnings	4	-	-	-	(5)	(1)
	61	(4)	-	(5)	(5)	47
Balance at September 30, 2012	(657)	489	(1,325)	(25)	(272)	(1,790)

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Commodity costs in the Consolidated Statements of Earnings.
3 Reported within Other income in the Consolidated Statements of Earnings.
4 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. RECIPROCAL SHAREHOLDING

At December 31, 2012, Noverco owned an approximate 6.0% reciprocal shareholding in the common shares of the Company. On May 28, 2013, Noverco sold 15 million Enbridge common shares through a secondary offering, thereby reducing the Company's reciprocal shareholding to approximately 3.9% and resulting in an increase in equity. Enbridge's share of the net after-tax proceeds of approximately $248 million was received as dividends from Noverco on June 4, 2013.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE 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 price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price 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 2018 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 $10,558 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.7%.

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 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 September 30, 2013 or December 31, 2012.

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

September 30, 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	**4**	**14**	**76**	**94**	**(20)**	**74**
Interest rate contracts	**25**	**-**	**11**	**36**	**(11)**	**25**
Commodity contracts	**7**	**-**	**208**	**215**	**(83)**	**132**
Other contracts	**1**	**-**	**9**	**10**	**-**	**10**
	37	**14**	**304**	**355**	**(114)**	**241**
Deferred amounts and other assets						
Foreign exchange contracts	**9**	**47**	**58**	**114**	**(87)**	**27**
Interest rate contracts	**331**	**-**	**3**	**334**	**(67)**	**267**
Commodity contracts	**7**	**-**	**59**	**66**	**(36)**	**30**
Other contracts	**1**	**-**	**2**	**3**	**(1)**	**2**
	348	**47**	**122**	**517**	**(191)**	**326**
Accounts payable and other						
Foreign exchange contracts	**(3)**	**-**	**(28)**	**(31)**	**20**	**(11)**
Interest rate contracts	**(365)**	**-**	**(11)**	**(376)**	**23**	**(353)**
Commodity contracts	**(11)**	**-**	**(175)**	**(186)**	**83**	**(103)**
	(379)	**-**	**(214)**	**(593)**	**126**	**(467)**
Other long-term liabilities						
Foreign exchange contracts	**(17)**	**(13)**	**(176)**	**(206)**	**87**	**(119)**
Interest rate contracts	**(149)**	**-**	**(4)**	**(153)**	**55**	**(98)**
Commodity contracts	**(3)**	**-**	**(471)**	**(474)**	**36**	**(438)**
Other contracts	**(1)**	**-**	**(1)**	**(2)**	**1**	**(1)**
	(170)	**(13)**	**(652)**	**(835)**	**179**	**(656)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(7)**	**48**	**(70)**	**(29)**	**-**	**(29)**
Interest rate contracts	**(158)**	**-**	**(1)**	**(159)**	**-**	**(159)**
Commodity contracts	**-**	**-**	**(379)**	**(379)**	**-**	**(379)**
Other contracts	**1**	**-**	**10**	**11**	**-**	**11**
	(164)	**48**	**(440)**	**(556)**	**-**	**(556)**

December 31, 2012	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	4	16	210	230	(101)	129
Interest rate contracts	7	-	9	16	(9)	7
Commodity contracts	9	-	119	128	(28)	100
Other contracts	3	-	6	9	-	9
	23	16	344	383	(138)	245
Deferred amounts and other assets						
Foreign exchange contracts	11	79	225	315	(40)	275
Interest rate contracts	18	-	12	30	(25)	5
Commodity contracts	1	-	59	60	(32)	28
Other contracts	2	-	1	3	-	3
	32	79	297	408	(97)	311
Accounts payable and other						
Foreign exchange contracts	(5)	-	(100)	(105)	101	(4)
Interest rate contracts	(673)	-	-	(673)	9	(664)
Commodity contracts	(3)	-	(294)	(297)	28	(269)
	(681)	-	(394)	(1,075)	138	(937)
Other long-term liabilities						
Foreign exchange contracts	(41)	(5)	(23)	(69)	40	(29)
Interest rate contracts	(290)	-	(15)	(305)	25	(280)
Commodity contracts	(2)	-	(387)	(389)	32	(357)
	(333)	(5)	(425)	(763)	97	(666)
Total net derivative asset/(liability)						
Foreign exchange contracts	(31)	90	312	371	-	371
Interest rate contracts	(938)	-	6	(932)	-	(932)
Commodity contracts	5	-	(503)	(498)	-	(498)
Other contracts	5	-	7	12	-	12
	(959)	90	(178)	(1,047)	-	(1,047)

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

September 30, 2013	2013	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**281**	**468**	**25**	**25**	**413**	**2**	**4**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,657**	**2,402**	**2,751**	**2,323**	**2,557**	**1,649**	**3,771**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**1**	**3**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**989**	**4,863**	**5,049**	**4,880**	**3,845**	**201**	**53**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**2,084**	**3,817**	**1,769**	**1,797**	**1,090**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**40**	**37**	**38**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**37**	**22**	**11**	**10**	**11**	**3**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**3**	**34**	**29**	**23**	**18**	**9**	**-**
Commodity contracts - NGL *(millions of barrels)*	**7**	**9**	**1**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**52**	**55**	**5**	**20**	**40**	**30**	**16**

December 31, 2012	2013	2014	2015	2016	2017	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	558	468	25	25	413	6
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,088	2,402	2,751	2,323	2,557	158
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	6	-	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,644	3,591	3,455	3,157	2,841	171
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	4,590	3,055	1,760	1,142	-	-
Equity contracts *(millions of Canadian dollars)*	39	36	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	55	19	10	10	11	3
Commodity contracts - crude oil *(millions of barrels)*	37	38	29	23	18	9
Commodity contracts - NGL *(millions of barrels)*	1	2	-	-	-	-
Commodity contracts - power *(MWH)*	51	67	48	63	83	66

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(18)**	(28)	**29**	(19)
Interest rate contracts	**(86)**	(1)	**703**	(190)
Commodity contracts	**(23)**	(27)	**(6)**	54
Other contracts	**(3)**	(3)	**(4)**	(3)
Net investment hedges				
Foreign exchange contracts	**25**	34	**(42)**	16
	(105)	(25)	**680**	(142)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(2)**	2	**(5)**	1
Interest rate contracts[2]	**43**	(7)	**89**	17
Commodity contracts[3]	**5**	-	**1**	(3)
	46	(5)	**85**	15
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**1**	(1)	**24**	3
Commodity contracts[3]	**-**	4	**(2)**	(1)
	1	3	**22**	2

1 Reported within Other income in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Commodity costs in the Consolidated Statements of Earnings.

The Company estimates that $84 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 51 months at September 30, 2013.

Non-Qualifying Derivatives

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**319**	303	**(382)**	242
Interest rate contracts[2]	**(2)**	(1)	**(7)**	(2)
Commodity contracts[3]	**20**	(531)	**124**	(973)
Other contracts[4]	**(1)**	(2)	**3**	3
Total unrealized derivative fair value gains/(loss)	**336**	(231)	**(262)**	(730)

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments, 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 one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at September 30, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

	September 30, 2013	December 31, 2012
(millions of Canadian dollars)		
Canadian financial institutions	**285**	306
United States financial institutions	**192**	129
European financial institutions	**190**	244
Other[1]	**135**	128
	802	807

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

As at September 30, 2013, the Company had provided letters of credit totaling $155 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held $12 million of cash collateral on asset exposures at September 30, 2013 and held no cash collateral at December 31, 2012.

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. 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 DERIVATIVES

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. The Company does not have any other financial instruments categorized as Level 1.

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 physical derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power swaps and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

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

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

September 30, 2013	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**94**	**-**	**94**
Interest rate contracts	**-**	**36**	**-**	**36**
Commodity contracts	**11**	**93**	**111**	**215**
Other contracts	**-**	**10**	**-**	**10**
	11	**233**	**111**	**355**
Long-term derivative assets				
Foreign exchange contracts	**-**	**114**	**-**	**114**
Interest rate contracts	**-**	**334**	**-**	**334**
Commodity contracts	**-**	**48**	**18**	**66**
Other contracts	**-**	**3**	**-**	**3**
	-	**499**	**18**	**517**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(31)**	**-**	**(31)**
Interest rate contracts	**-**	**(376)**	**-**	**(376)**
Commodity contracts	**(1)**	**(78)**	**(107)**	**(186)**
	(1)	**(485)**	**(107)**	**(593)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(206)**	**-**	**(206)**
Interest rate contracts	**-**	**(153)**	**-**	**(153)**
Commodity contracts	**-**	**(324)**	**(150)**	**(474)**
Other contracts	**-**	**(2)**	**-**	**(2)**
	-	**(685)**	**(150)**	**(835)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(29)**	**-**	**(29)**
Interest rate contracts	**-**	**(159)**	**-**	**(159)**
Commodity contracts	**10**	**(261)**	**(128)**	**(379)**
Other contracts	**-**	**11**	**-**	**11**
	10	**(438)**	**(128)**	**(556)**

December 31, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	230	-	230
Interest rate contracts	-	16	-	16
Commodity contracts	3	7	118	128
Other contracts	-	9	-	9
	3	262	118	383
Long-term derivative assets				
Foreign exchange contracts	-	315	-	315
Interest rate contracts	-	30	-	30
Commodity contracts	-	51	9	60
Other contracts	-	3	-	3
	-	399	9	408
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(105)	-	(105)
Interest rate contracts	-	(673)	-	(673)
Commodity contracts	(9)	(212)	(76)	(297)
	(9)	(990)	(76)	(1,075)
Long-term derivative liabilities				
Foreign exchange contracts	-	(69)	-	(69)
Interest rate contracts	-	(305)	-	(305)
Commodity contracts	-	(314)	(75)	(389)
	-	(688)	(75)	(763)
Total net financial asset/(liability)				
Foreign exchange contracts	-	371	-	371
Interest rate contracts	-	(932)	-	(932)
Commodity contracts	(6)	(468)	(24)	(498)
Other contracts	-	12	-	12
	(6)	(1,017)	(24)	(1,047)

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

September 30, 2013	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	1	Forward gas price	3.24	4.33	3.81	$/mmbtu[3]
Crude	(3)	Forward crude price	65.87	110.08	74.85	$/barrel
NGL	(3)	Forward NGL price	0.25	2.08	1.33	$/gallon
Power	(137)	Forward power price	43.00	73.00	58.77	$/MWH
Commodity contracts - physical[1]						
Natural gas	(6)	Forward gas price	3.01	4.92	3.74	$/mmbtu[3]
Crude	14	Forward crude price	67.49	113.07	92.43	$/barrel
NGL	(1)	Forward NGL price	0.01	2.55	1.55	$/gallon
Power	(1)	Forward power price	30.98	36.75	33.17	$/MWH
Commodity options[2]						
Natural gas	1	Option volatility	29%	36%	33%	
NGL	7	Option volatility	24%	145%	43%	
	(128)					

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

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

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

	Nine months ended September 30,	
	2013	2012
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**(24)**	32
Total gains/(loss)		
Included in earnings[1]	**(92)**	(52)
Included in OCI	**(2)**	3
Settlements	**(10)**	(7)
Level 3 net derivative asset/(liability) at end of period	**(128)**	(24)

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at September 30, 2013 or 2012.

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 totaled $90 million at September 30, 2013 (December 31, 2012 - $66 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $274 million at September 30, 2013 (December 31, 2012 - $246 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 September 30, 2013, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2012 - $580 million).

At September 30, 2013, the Company's long-term debt had a carrying value of $22,306 million (December 31, 2012 - $20,855 million) and a fair value of $24,538 million (December 31, 2012 - $24,809 million).

12. INCOME TAXES

The effective income tax rates for the three and nine months ended September 30, 2013 were 35.7% and 31.5%, respectively (2012 - 0.6% and 1.7%, respectively). In 2012, the effective rate reflected significant losses relating to certain risk management activities in the Company's United States operations and the higher United States income tax rate over the Canadian federal statutory rate. The losses did not persist in the three or nine months ended September 30, 2013. Further, income taxes for the three and nine months ended September 30, 2013 included an out-of-period correction as described in Note 4, Segmented Information, increasing the effective income tax rate compared with the corresponding periods of 2012.

The gross change for current year uncertain tax positions included an increase of $9 million with respect to Texas Margin Tax and a decrease of $18 million recognizing the tax benefit pertaining to changes for tax on preferred share dividends which became enacted law during the second quarter of 2013.

13. RETIREMENT AND POSTRETIREMENT BENEFITS

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

NET BENEFIT COSTS RECOGNIZED

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Benefits earned during the period	**30**	23	**87**	71
Interest cost on projected benefit obligations	**23**	20	**66**	61
Expected return on plan assets	**(27)**	(23)	**(79)**	(71)
Amortization of prior service costs	**-**	1	**1**	1
Amortization of actuarial loss	**14**	5	**40**	17
Net benefit costs on an accrual basis[1,2]	**40**	26	**115**	79

1 Included in net benefit costs for the three and nine months ended September 30, 2013 are costs related to OPEB of $4 million and $13 million (2012 - $4 million and $13 million).

2 For the three and nine months ended September 30, 2013, offsetting regulatory assets of $1 million and $3 million (2012 - $6 million and $16 million) have been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

14. 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.

Lakehead System Crude Oil Releases

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 of 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 September 30, 2013, EEP's total cost estimate for the Line 6B crude oil release was US$1,035 million ($167 million after-tax attributable to Enbridge) which is an increase of US$215 million ($30 million after-tax attributable to Enbridge) compared with the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the Pipeline and Hazardous Materials Safety Administration (PHMSA) civil penalty of US$3.7 million which was paid in the third quarter of 2012. On March 14, 2013, EEP received an Order from the Environmental Protection Agency (EPA) (the Order) 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. 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. The Order states the work must be completed by December 31, 2013.

The US$175 million increase in the total cost estimate during the three month period ended March 31, 2013 was attributable to additional work required by the Order. The US$40 million increase during the three month period ended June 30, 2013 was attributable to further refinement and definition of the additional dredging scope per the Order and all associated environmental, permitting, waste removal and other related costs. The actual costs incurred may differ from the foregoing estimate as EEP completes the work plan with the EPA related to the Order and works with other regulatory agencies to assure its work plan complies with their requirements. Any such incremental costs will not be recovered under EEP's insurance policies as the costs for the incident at September 30, 2013 exceeded the limits of its insurance coverage.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2013. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois on September 9, 2010, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release remains at US$48 million ($7 million after-tax attributable to Enbridge).

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 such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

The claims for 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. Based on EEP's remediation spending through September 30, 2013, 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. During the third quarter of 2013, EEP received US$42 million ($6 million after-tax attributable to Enbridge) of insurance recoveries for a claim filed in connection with the Line 6B crude oil release previously recognized as a reduction to environmental costs in the second quarter of 2013. EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) of insurance recoveries as reductions to environmental costs for the three and nine months ended September 30, 2012 for the Line 6B crude oil release. As at September 30, 2013, EEP has recorded total insurance recoveries of US$547 million for the Line 6B crude oil release, out of the US$650 million aggregate limit. EEP expects to record receivables for additional amounts claimed for recovery pursuant to its insurance policies during the period that EEP deems realization of the claim for recovery to be probable.

Effective May 1, 2013, Enbridge renewed its comprehensive property and liability insurance programs, under which EEP is insured through April 30, 2014, with a current liability aggregate limit of US$685 million, including sudden and accidental pollution liability. 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 the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 30 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, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a Notice of Probable Violation related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. One claim related to the Line 6A crude oil release has been filed against one of EEP's affiliates by the State of Illinois in an Illinois state court. The parties are currently operating under an agreed interim order.

EEP expects that it will be required to pay civil penalties under the Clean Water Act of the United States in respect of the Line 6B crude oil release. As a result of recent communications from responsible governmental agencies, EEP expects to accrue US$22 million in the fourth quarter of 2013 in respect of these matters. 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, US$22 million represents the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed or required by 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 preliminary and ongoing.

As this matter represents a subsequent event to Enbridge, costs of $5 million after-tax attributable to Enbridge have been recognized as Environmental costs for the three and nine months ended September 30, 2013. The amount of any final fine and penalty or cost of injunctive relief may differ materially from the amount accrued as at September 30, 2013.

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 September 30,		Nine months ended September 30,	
	2013	2012	**2013**	2012
(unaudited; millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders[1]				
Liquids Pipelines	**301**	276	**381**	567
Gas Distribution	**(85)**	(18)	**49**	80
Gas Pipelines, Processing and Energy Services	**68**	(191)	**257**	(409)
Sponsored Investments	**75**	80	**189**	211
Corporate	**62**	40	**(163)**	7
	421	187	**713**	456
Earnings per common share[1]	**0.52**	0.24	**0.89**	0.59
Diluted earnings per common share[1]	**0.51**	0.24	**0.88**	0.59
Adjusted earnings[1,2]				
Liquids Pipelines	**187**	187	**565**	478
Gas Distribution	**(29)**	(18)	**109**	113
Gas Pipelines, Processing and Energy Services	**54**	46	**186**	134
Sponsored Investments	**86**	69	**224**	196
Corporate	**(20)**	(17)	**(12)**	(7)
	278	267	**1,072**	914
Adjusted earnings per common share[1]	**0.34**	0.34	**1.33**	1.19
Cash flow data				
Cash provided by operating activities	**830**	740	**2,560**	2,372
Cash used in investing activities	**(2,562)**	(1,619)	**(6,154)**	(4,022)
Cash provided by financing activities	**1,175**	1,949	**2,326**	2,670
Dividends				
Common share dividends declared	**261**	225	**774**	668
Dividends paid per common share	**0.3150**	0.2825	**0.9450**	0.8475
Shares outstanding *(millions)*				
Weighted average common shares outstanding	**814**	780	**803**	769
Diluted weighted average common shares outstanding	**824**	792	**814**	781
Operating data				
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*				
Canadian Mainline[3]	**1,736**	1,617	**1,707**	1,654
Regional Oil Sands System[4]	**578**	387	**490**	390
Spearhead Pipeline	**172**	155	**174**	157
Gas Distribution - Enbridge Gas Distribution (EGD)				
Volumes *(billions of cubic feet)*	**44**	45	**299**	272
Number of active customers *(thousands)*[5]	**2,040**	2,007	**2,040**	2,007
Heating degree days[6]				
Actual	**89**	83	**2,378**	1,989
Forecast based on normal weather	**54**	80	**2,420**	2,328
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,514**	1,448	**1,569**	1,555
Vector Pipeline	**1,406**	1,384	**1,511**	1,519
Enbridge Offshore Pipelines	**1,458**	1,508	**1,420**	1,537

1 Earnings attributable to common shareholders and Adjusted earnings, along with corresponding per common share amounts, for the three and nine months ended September 30, 2012 have been revised. See Note 2 to the September 30, 2013 Consolidated Financial Statements.

2 Adjusted earnings represent earnings attributable to common shareholders adjusted for 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.

3 Canadian Mainline includes deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries entering the mainline in western Canada.

4 *Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*
5 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*
6 *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:

CIBC Mellon Trust Company
P.O. Box 7010,
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
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 2013 fourth quarter optional cash payment to purchase additional shares is November 25, 2013.

Investor Relations

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

Investor Relations
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Toll free: (800) 481-2804
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November 6, 2013

ENBRIDGE

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