ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 14, 2014 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2013, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

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 4, Revision of Prior Period Financial Statements, to the consolidated financial statements as at December 31, 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 year ended December 31, 2013 or other comparative periods as indicated.

OVERVIEW

Enbridge, a Canadian Company, is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has significant and growing involvement in natural gas gathering, transmission and midstream businesses and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in more than 1,800 megawatts (MW) of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal facilities. Enbridge has approximately 10,000 employees and contractors, primarily in Canada and the United States.

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

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

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

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

Investments in natural gas pipelines include the Company's interests in the United States portion of the Alliance System (Alliance Pipeline US), the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance System (Alliance). The energy services businesses undertake physical commodity marketing activity and logistical services, refinery supply services and manage the Company's volume commitments on the Alliance, Vector and other pipeline systems.

SPONSORED INVESTMENTS
Sponsored Investments includes the Company's 20.6% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 67.3% economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge, through its subsidiaries, manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

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

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

PERFORMANCE OVERVIEW

	Three Months Ended December 31,		Year Ended December 31,		
	2013	2012	**2013**	2012	2011
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**46**	130	**427**	697	470
Gas Distribution	**80**	127	**129**	207	(88)
Gas Pipelines, Processing and Energy Services	**(325)**	32	**(68)**	(377)	328
Sponsored Investments	**79**	72	**268**	283	268
Corporate	**(151)**	(136)	**(314)**	(129)	(171)
Earnings/(loss) attributable to common shareholders from continuing operations	**(271)**	225	**442**	681	807
Discontinued operations - Gas Pipelines, Processing and Energy Services	**4**	(79)	**4**	(79)	(6)
	(267)	146	**446**	602	801
Earnings/(loss) per common share	**(0.33)**	0.19	**0.55**	0.78	1.07
Diluted earnings/(loss) per common share	**(0.32)**	0.18	**0.55**	0.77	1.05
Adjusted earnings[1]					
Liquids Pipelines	**205**	177	**770**	655	501
Gas Distribution	**67**	63	**176**	176	173
Gas Pipelines, Processing and Energy Services	**17**	42	**203**	176	180
Sponsored Investments	**89**	68	**313**	264	243
Corporate	**(16)**	(23)	**(28)**	(30)	(16)
	362	327	**1,434**	1,241	1,081
Adjusted earnings per common share[1]	**0.44**	0.42	**1.78**	1.61	1.44
Cash flow data					
Cash provided by operating activities	**781**	502	**3,341**	2,874	3,371
Cash used in investing activities	**(3,277)**	(2,182)	**(9,431)**	(6,204)	(5,079)
Cash provided by financing activities	**2,744**	1,725	**5,070**	4,395	2,030
Dividends					
Common share dividends declared	**261**	227	**1,035**	895	759
Dividends paid per common share	**0.3150**	0.2825	**1.26**	1.13	0.98
Revenues					
Commodity sales	**6,939**	4,978	**26,039**	18,494	20,374
Gas distribution sales	**710**	585	**2,265**	1,910	1,906
Transportation and other services	**644**	1,444	**4,614**	4,256	4,509
	8,293	7,007	**32,918**	24,660	26,789
Total assets	**57,568**	46,800	**57,568**	46,800	41,130
Total long-term liabilities	**28,277**	25,227	**28,277**	25,227	23,958

1 Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 7.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $446 million ($0.55 per common share) for the year ended December 31, 2013 compared with $602 million ($0.78 per common share) for the year ended December 31, 2012 and $801 million ($1.07 per common share) for the year ended December 31, 2011. The Company has delivered significant earnings growth from operations over the course of the last three years, as discussed below in *Performance Overview – Adjusted Earnings*; however, the positive impact of this growth and the comparability of the Company's earnings are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains or losses. The Company has a comprehensive long-term economic hedging program to mitigate exposures to interest rate, foreign exchange and commodity prices. 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.

Also impacting the comparability of earnings between fiscal years were certain out-of-period adjustments recognized in 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.

Other significant items impacting the comparability of earnings year-over-year were costs and related insurance recoveries associated with the Line 6B crude oil release. Earnings for the years ended December 31, 2013, 2012 and 2011 included EEP's cost estimates of US$302 million ($44 million after-tax attributable to Enbridge), US$55 million ($8 million after-tax attributable to Enbridge) and US$215 million ($33 million after-tax attributable to Enbridge), respectively. The aforementioned costs are before insurance recoveries and excluding additional fines and penalties other than the fines and penalties discussed under *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Line 6B Crude Oil Release.* Insurance recoveries recorded by EEP for the years ended December 31, 2013, 2012 and 2011 were US$42 million ($6 million after-tax attributable to Enbridge), US$170 million ($24 million after-tax attributable to Enbridge) and US$335 million ($50 million after-tax attributable to Enbridge), respectively, related to the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Insurance Recoveries*. Within Liquids Pipelines, 2013 earnings reflected remediation and long-term stabilization costs of approximately $56 million after-tax and before insurance recoveries related to the Line 37 crude oil release that occurred in June 2013. See *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release.*

Fourth quarter earnings drivers were largely consistent with year-to-date trends and continued to include changes in unrealized fair value derivative and foreign exchange gains and losses. Aside from operating factors discussed in *Performance Overview – Adjusted Earnings*, factors unique to the fourth quarter of 2013 included a further recognition of US$65 million ($9 million after-tax attributable to Enbridge) of costs related to the Line 6B crude oil release and an additional $3 million after-tax accrual related to Line 37 remediation activities.

ADJUSTED EARNINGS

A key tenet of the Company's investor value proposition is "visible growth", supported by an ongoing focus on safe and reliable operations and a disciplined approach to investment and project execution. The Company has consistently delivered on this proposition, growing adjusted earnings from $1.44 per common share in 2011 to $1.61 per common share in 2012 and $1.78 per common share in 2013.

The upward trend in adjusted earnings over these years was predominantly attributable to strong operating performance from the Company's Liquids Pipelines assets and contributions from new assets placed into service. The Canadian Mainline has performed favourably under the Competitive Toll Settlement (CTS) which took effect mid-2011 and has benefitted from heightened throughput since that time. Strong supply from western Canada and the ongoing effect of crude oil price differentials, whereby demand for discounted crude by United States midwest refiners remained high, drove increased throughput on Canadian Mainline in both 2013 and 2012. New Liquids Pipelines assets placed into service in recent years included the Woodland and Wood Buffalo pipelines which, together with expanded capacity on Seaway Crude Pipeline System (Seaway Pipeline), contributed to adjusted earnings growth in 2013. Renewable energy investments continued to be an important component of Enbridge's strategy to diversify and sustain longer-term earnings growth. Between 2011 and 2013 Enbridge placed into service five wind farms and two solar farms, and commenced operations of its first power transmission project in mid-2013. Adjusted earnings for the year ended December 31, 2013 also reflected contributions from the Company's recent entry into the Canadian natural gas midstream infrastructure space.

Enbridge's sponsored vehicles, EEP and the Fund, also contributed to the year-over-year adjusted earnings growth. The Fund benefitted from an expanded asset base following the acquisition of assets from Enbridge (drop down transactions) in both 2011 and 2012, as well as completion of the Bakken Expansion Project, a project undertaken jointly with EEP. In addition to expanding its North Dakota regional infrastructure, EEP was also successful in completing several other organic growth projects, including the Texas Express NGL System joint venture and the Ajax Cryogenic Processing Plant (Ajax Plant). EEP's Lakehead System benefitted from strong volumes in both 2012 and 2013, similar to Canadian Mainline, while its natural gas and NGL businesses continued to experience lower volumes and prices due to declining drilling activity in dry gas basins of the United States as a result of a sustained low natural gas commodity price environment.

Other factors which contributed to changes in adjusted earnings year-over-year included market factors impacting the Company's Energy Services businesses and its Aux Sable fractionation plant, as well as the Company's continued activity in the capital markets through the issuance of preference shares and debt to fund future growth projects. After a decrease in adjusted earnings in 2012 compared with 2011 due to unfavourable market conditions, Energy Services earnings increased in 2013 as changing market conditions gave rise to a greater number of and more profitable margin opportunities. Reflecting the opposite trend, Aux Sable adjusted earnings increased in 2012 over 2011 due to new assets being placed into service and higher fractionation margins, but declined in 2013 on lower fractionation margins and lower ethane processing volumes due to ethane rejections.

With respect to the fourth quarter of 2013, many of these same annual trends continued. The primary drivers of quarter-over-quarter adjusted earnings growth were volume increases on Canadian Mainline, contributions from new assets placed into service in Regional Oil Sands System and higher contributions from EEP's liquids business due to a combination of higher throughput and tolls. Although no full year effect, the fourth quarter of 2013 also included a favourable adjustment in Regional Oil Sands System related to a reduction in third party revenue sharing with the founding shipper on the Athabasca pipeline. Partially offsetting earnings growth in the fourth quarter of 2013 was a loss incurred by Energy Services due to changing market conditions, which gave rise to losses on certain physical positions, in addition to losses on financial contracts intended to hedge the value of committed physical transportation capacity but which were ineffective in doing so in the last three months of the year.

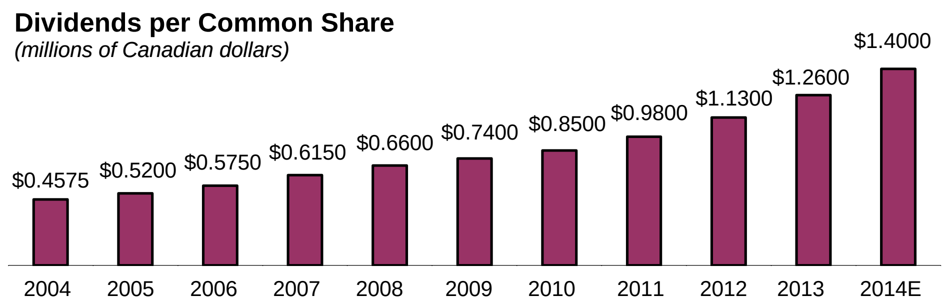
CASH FLOWS

Cash provided by operating activities was $3,341 million for the year ended December 31, 2013, mainly driven by strong operating performance from the Company's core assets, particularly from Liquids Pipelines, and the cash flow generation from growth projects placed into service in recent years. In addition, during 2013, upon realization of a substantial gain on the disposition of a portion of its investment in Enbridge shares, Noverco paid Enbridge a one-time dividend of $248 million. Partially offsetting these cash inflows were changes in operating assets and liabilities which fluctuate in the normal course due to various factors impacting the timing of cash receipts and payments.

In 2013, the Company was active in the capital markets with the issuance of $1,428 million in preference shares, common shares of approximately $628 million and $2,845 million in medium-term notes and also significantly bolstered its liquidity through the securement of additional credit facilities. The proceeds of the capital market transactions, together with additional borrowings from its credit facilities, cash generated from operations and cash on hand were more than sufficient to finance the Company's nearly $10 billion net investment in expansion initiatives during 2013, and are expected to provide financing flexibility for the Company's growth opportunities in 2014.

DIVIDENDS

The Company has paid common share dividends since it became a publicly traded company in 1953. In December 2013, the Company announced an 11% increase in its quarterly dividend to $0.35 per common share, or $1.40 annualized,



effective March 1, 2014. Assuming this currently announced quarterly dividend is annualized for 2014, the Company has generated compound annual average growth of 11.8% since 2004. The Company continues to target a dividend payout of approximately 60% to 70% of adjusted earnings over the longer term. In 2013, the dividend payout was 71% (2012 - 70%; 2011 - 67%) of adjusted earnings per share.

REVENUES

The Company generates revenue from three primary sources: commodity sales, gas distribution sales and transportation and other services. Commodity sales of $26,039 million for the year ended December 31, 2013 (2012 - $18,494 million; 2011 - $20,374 million) were earned through the Company's energy services operations. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices. Commodity prices do not directly impact earnings since these earnings reflect a margin or percentage of revenue which depends more on differences in commodity prices between locations and points in time than on the absolute level of prices.

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

Transportation and other services revenues are earned from the Company's crude oil and natural gas pipeline transportation businesses and also includes power production revenues from the Company's portfolio of renewable and power generation assets. For the Company's transportation assets operating under market-based arrangements, revenues are driven by volumes transported and tolls. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, is reflective of the Company's cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on the Company's core liquids pipeline assets as well as new assets placed into service during 2013.

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

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', *‘‘believe’’ and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: 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, NGL and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company’s projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company’s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, and may impact levels of demand for the Company’s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service date and expected capital expenditures include: the availability and price of labour and construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

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

NON-GAAP MEASURES

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

therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

CORPORATE VISION AND STRATEGY

VISION

Enbridge's vision is to be the leading energy delivery company in North America. The Company transports, distributes and generates energy and its primary purpose is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.

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

STRATEGY

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

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

Commitment to Safety and Operational Reliability

The commitment to safety and operational reliability means achieving industry leadership in process, public and personal safety, operational reliability and integrity of the Company's pipelines and facilities and the protection of the environment. This is the Company's number one priority and sets the foundation for the strategic plan.

Under the umbrella of the Company's Operational Risk Management (ORM) Plan introduced in 2011, the Company has undertaken extensive maintenance, integrity and inspection programs across its pipeline systems. The ORM Plan has also bolstered incident response capabilities, employee and public safety and improved communications with landowners and first responders. In 2013, Enbridge established the role of Senior Vice President, Enterprise Safety & Operational Reliability, a new centralized role accountable for defining and executing on an enterprise-wide vision, culture and set of integrated strategies and policies that support the Company's ORM objectives.

Execute

Focus on Project Management

Enbridge's objective is to safely deliver projects on time and on budget and at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction, environmental and regulatory compliance. With an approximate $29 billion portfolio of commercially secured projects, successful project execution is critical to achieving the Company's long-term growth plan. Enbridge, through its Major Projects group (Major Projects), continues to build upon its rigorous project management processes including: employee and contractor safety; long-term supply chain agreements; quality design, materials and construction; extensive regulatory and public consultation; robust cost, schedule and risk controls; and efficient project transition to operating units.

Preserve Financial Strength and Flexibility

The maintenance of adequate financial strength and flexibility is crucial to Enbridge's growth strategy. Enbridge's financial strategies are designed to ensure the Company has sufficient financial flexibility to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain or improve its credit ratings, diversify its funding sources and maintain substantial standby bank credit capacity and access to capital markets in both Canada and the United States.

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

Secure the Longer-Term Future

Strengthen Core Businesses

Within Liquids Pipelines, strategies are focused on providing access to new markets for growing production from western Canada and the Bakken, optimizing and expanding mainline operations and expanding regional oil sands infrastructure. Through Enbridge's market access initiatives, shippers will be provided greater connectivity to markets in Ontario, Quebec, the Gulf Coast and upper-midwest helping secure the best pricing for their products depending on crude type. Significant market access programs include Gulf Coast Access, Eastern Access and Light Oil Market Access. In 2013, the Company made significant progress on each of these market initiatives including the completion of the Seaway Pipeline expansion to increase transportation capacity to the Gulf Coast to up to 400,000 barrels per day (bpd) depending on crude oil slate. To facilitate these downstream growth projects and continued growth in base volumes, a number of supporting mainline expansions are being undertaken. In addition, the Company is also focused on maximizing existing operating capacity through optimization initiatives such as improved scheduling and tankage management.

The objective of Regional Oil Sands System expansion is to optimize existing asset corridors to secure incremental supply expected from the western Canadian oil sands over the next decade. The Company currently has approximately $6 billion of regional infrastructure under development, including the expansion and twinning of the Athabasca pipeline; the extension of the Wood Buffalo Pipeline (Wood Buffalo Extension); and the Norlite Pipeline System (Norlite), which will transport diluent from the Edmonton region to oil sands producers.

The Company's natural gas strategies include leveraging the competitive advantages of its existing assets and expanding its footprint in emerging areas. Combined, Alliance and the Aux Sable NGL fractionation plant are well positioned to provide liquids-rich gas transportation and processing to developing regions in northeast British Columbia, western Alberta and the Bakken. Alliance is also evaluating opportunities to expand service offerings in those areas.

Enbridge is also partnering with producers to develop needed Canadian midstream infrastructure. In addition to these onshore strategies, the Company continues to pursue crude oil and natural gas gathering expansion opportunities for ultra-deep projects in the Gulf of Mexico, building on momentum achieved with the Walker Ridge Gas Gathering System (WRGGS), Big Foot Oil Pipeline (Big Foot Pipeline) and Heidelberg Lateral Pipeline (Heidelberg) projects currently under construction.

Develop New Platforms for Growth and Diversification

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

Enbridge has advanced its renewable power strategy considerably over the past several years and has interests in a renewable energy portfolio with a generation capacity of more than 1,800 MW. Since the beginning of 2013, the Company has been successful in securing several projects, including the Keechi Wind Project (Keechi) in Texas, Blackspring Ridge Wind Project (Blackspring Ridge) in Alberta and the Saint Robert Bellarmin Wind Project in Quebec, which collectively will have the capacity to generate an approximate 500 MW of renewable energy.

Maintain the Foundation

Uphold Enbridge Values

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

Maintain the Company's Social License to Operate

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

One of Enbridge's CSR environmental objectives is its Neutral Footprint plan, which includes initiatives to counteract the environmental impact of all Enbridge's pipeline expansion projects. Neutral Footprint initiatives include:

- planting a tree for every tree the Company removes to build new pipelines and facilities;
- conserving an acre of natural habitat for every acre the Company permanently alters; and
- generating a kilowatt hour of renewable energy for every kilowatt hour the Company's expansions consume.

The 2013 CSR Report can be found at http://csr.enbridge.com and progress updates on the Company's Neutral Footprint initiatives can be found at http://www.enbridge.com/neutralfootprint and in the annual CSR Report. ***None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.***

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

Retain, Attract and Develop Highly Capable People

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

INDUSTRY FUNDAMENTALS

SUPPLY AND DEMAND FOR LIQUIDS

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

Global energy consumption is expected to continue to grow, with the growth in crude oil demand primarily driven by non-Organisation for Economic Co-operation and Development (OECD) regions, such as Asia and the Middle East, with China expected to be the largest single growth market. In OECD countries, including Canada, the United States and western European nations, conservation, limited population growth and a shift to alternative energy will reduce crude oil demand over the long-term. Accordingly, there is a strategic opportunity for North American producers to meet growing global demand outside North America.

In terms of supply, North American crude oil production growth is expected to outpace growth from Organization of the Petroleum Exporting Countries over the 2014 to 2030 time period. The primary driver of the production growth stems from the expansion of shale oil and oil sands production. The emergence of shale oil plays, including the Bakken in North Dakota, have altered the United States crude oil production landscape and is expected to double total United States crude oil production over the next 20 years, although the rate of growth could be tempered by increased environmental regulation in future years. In Canada, the Western Canadian Sedimentary Basin (WCSB) continues to be viewed as one of the world's largest and most secure supply sources of crude oil. Investment in the WCSB continues to be strong and several new projects and expansions of existing oil sands production facilities have been added or accelerated due to supportive oil prices and increased foreign investment.

The combination of relatively flat domestic demand, growing supply and shortages of pipeline infrastructure, has led to volatile crude oil price differentials in North America. In recent years, an over-supply to land-locked markets has resulted in a divergence between West Texas Intermediate (WTI) and world pricing, resulting in lower netbacks for North American producers than could otherwise be achieved if selling into global markets. The impact of price differentials has been even more pronounced for western Canadian producers as insufficient pipeline infrastructure has resulted in a further discounting of Alberta crude against WTI. To address these market challenges, crude oil transportation infrastructure will have to undergo a major change in configuration. While producers have sought alternative means of transportation, such as rail, to access higher netback markets in the short-term, pipelines will continue to be the most cost effective means of transportation for the longer-term.

Enbridge's role in helping to address the evolving supply and demand fundamentals, and improving netbacks for producers and supply costs to refiners, is to provide expanded pipeline capacity and sustainable connectivity to alternative markets. In 2013, Enbridge added to its growing slate of commercially secured projects within Liquids Pipelines to provide market access solutions and additional regional oil sands infrastructure. The Company's market access initiatives include the Gulf Coast Access Program, Eastern Access Program and Light Oil Market Access Program, all of which provide producers greater access to North American refinery markets.

Despite these initiatives, and those of competitors, heavy oil prices from western Canada will likely continue to lag behind world prices, heightening the need for access to growing Asian markets. Details of the Company's Northern Gateway Project (Northern Gateway), a proposed pipeline system from Alberta to the coast of British Columbia, and associated marine terminal, along with the Company's other projects under development, can be found in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development*.

SUPPLY AND DEMAND FOR NATURAL GAS AND NGL

The North American natural gas market is transitioning to a better balance as gas production growth has slowed after several years of robust increases. As a result, natural gas prices have firmed modestly over the past year. Natural gas supply remains ample and could respond quickly to rising demand, thereby limiting further price advances. As the economy recovers and natural gas prices remain relatively low, gas demand in the United States is expected to increase, primarily from the power generation and industrial sectors. Within Canada, natural gas demand growth is expected to be driven primarily by continued oil sands development.

The Northeast has become the primary source of United States natural gas supply growth as regional gas production has exceeded demand. The significant resource base within the Marcellus and Utica shale gas plays in the northeastern United States has fundamentally altered the flow pattern of gas in North America and is displacing Gulf Coast and WCSB supplies. While this presents opportunities for new regional infrastructure as natural gas producers seek alternative markets, it may also present challenges for existing infrastructure serving these supply areas.

In a weak natural gas price environment, producers have been shifting from dry gas drilling to developing rich gas reservoirs to take advantage of the relatively higher value of NGL inherent in the gas stream. NGL that can be extracted from liquids-rich gas streams include ethane, propane, butane and natural gasoline, which are used in a variety of industrial, commercial and other applications. Recently, extraction margins have been pressured by robust supply and corresponding weaker prices for ethane. This has led to significant ethane rejection and projects to export increased volumes of propane. The growing NGL supply is also straining the existing infrastructure capacity and causing regional price differentials. With the majority of petrochemical facilities located in the Gulf Coast, additional infrastructure will be required to expand processing facilities and take-away pipeline capacity.

Similar to crude oil, significant differentials exist between North American and world gas prices. While North American gas prices continue to be relatively low, the price for liquefied natural gas (LNG) in global markets is more closely linked to higher crude oil prices, providing an opportunity to capture more favourable netbacks on LNG exports from North America, if that pricing linkage is maintained. Based on the prospect for higher global LNG demand, the large resource base in western Canada and changing North American natural gas flow patterns discussed above, there is an increasing probability that one or more projects to export LNG off the west Coast of Canada will proceed.

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

SUPPLY AND DEMAND FOR RENEWABLE ENERGY

North American economic growth over the longer term is expected to drive growing electricity demand. Given the accelerated pace of retirement of aging coal-fired generation plants in North America after 2015 due to impending emission regulations, significant new generation capacity is expected to be required. While coal and nuclear facilities will continue to be a core component of power generation in North America, gas fired and renewable energy facilities, including biomass, hydro, solar and wind, are expected to be the preferred sources to replace coal-fired generation, due to their lower carbon intensities.

The United States National Renewable Energy Laboratory reports that North America has significant wind and solar resources, with wind alone having the potential to provide capacity for over 10,000 gigawatts of power generation. Solar resources in southwestern states such as Arizona, California and Nevada are considered to be the best in the world for large-scale solar plants. According to Environment Canada, Canada also has an abundance of wind and solar resources with particularly strong wind resources in the northeastern regions.

Expanding renewable energy infrastructure in North America is not without challenges. Growing renewable generation capacity is expected to necessitate substantial capital investment to upgrade existing transmission systems or, in many cases, build new transmission lines, as these high quality wind and solar resources are often found in regions which are not in close proximity to high demand markets. Furthermore, the profitability of renewable energy projects, to date, has in part been supported by certain tax and government incentives. In the near-term, uncertainty over the continuing availability of tax or other government incentives and the ability to secure long-term power purchase agreements (PPA) through government or investor-owned power authorities may hinder the pace of future new renewable capacity development. However, continued improvement in technology and manufacturing capacity in the past few years has reduced capital costs associated with renewable energy infrastructure and has also improved yield factors of power generation assets. These positive developments are expected to render renewable energy more competitive and support ongoing investment over the long-term.

Enbridge continues to be active in renewable asset development and secured the development of three additional wind farms in 2013; and now has interests in more than 1,800 MW of renewable energy generation capacity. In 2013, Enbridge also completed its first power transmission line, the Montana-Alberta Tie-Line (MATL). The Company will continue to seek new opportunities to grow its portfolio of renewable power generation and power transmission businesses that meet its investment criteria.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

In 2013, the Company was successful in placing approximately $5 billion of growth projects into service across several business units. Enbridge also added to its slate of commercially secured growth projects which now totals approximately $29 billion.

The Company's growth initiatives are anchored by three major market access initiatives, supported by several mainline system expansion projects which are designed to ensure that there is sufficient capacity to feed these new extensions. The three major market access initiatives are:

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

The $5.8 billion Gulf Coast Access Program includes the Seaway Pipeline, the Flanagan South Pipeline Project and elements of the Canadian Mainline and Lakehead System Mainline expansions and will increase access to refinery markets in the Gulf Coast. The $2.7 billion Eastern Access Program is expected to allow for greater access for crude oil into Chicago, further east into Toledo and ultimately into

Ontario and Quebec. The Eastern Access Program includes the Company's Toledo pipeline expansion, Line 9 reversal, the existing Spearhead North pipeline expansion, Line 6B replacement and Line 5 expansion. Finally, the $6.2 billion Light Oil Market Access Program brings together a group of projects to support the increasing supply of light oil from Canada and the Bakken and also supplement the Eastern Access Program through the upsize of the Line 9B and Line 6B capacity expansion. The Light Oil Market Access Program also includes the Southern Access Extension, the Sandpiper Project (Sandpiper), Canadian Mainline System Terminal Flexibility and Connectivity and twinning of the Spearhead North pipeline and Line 61 expansion included within the Lakehead System Mainline Expansion. The Company also has approximately $6 billion in regional infrastructure projects under development, solidifying its position as the largest pipeline operator in the oil sands region of Alberta.

In keeping with the Company's strategic priority to develop new platforms to diversify and sustain long-term growth, Enbridge continued to expand its renewable energy generation capacity in 2013. The Company secured wind power generation projects with a generation capacity of approximately 500 MW and also placed the 300-MW MATL, Enbridge's first power transmission project, into service.

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$0.6 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 (in phases)	Complete
4. Eastern Access[3]				
Toledo Expansion	US$0.2 billion	US$0.2 billion	2013	Complete
Line 9 Reversal and Expansion	$0.4 billion	$0.2 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	Substantially complete
7. Flanagan South Pipeline Project	US$2.8 billion	US$1.6 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	$0.6 billion	2015	Under construction
11. Edmonton to Hardisty Expansion	$1.8 billion	$0.2 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. Sunday Creek Terminal Expansion	$0.2 billion	$0.1 billion	2015	Pre-construction
15. Canadian Mainline System Terminal Flexibility and Connectivity	$0.6 billion	$0.2 billion	2013-2015 (in phases)	Under construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
16. Woodland Pipeline Extension	$0.6 billion	$0.1 billion	2015	Pre-construction
17. JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
18. Wood Buffalo Extension	$1.6 billion	No significant expenditures to date	2017	Pre-construction
19. Norlite Pipeline System	$1.4 billion	No significant expenditures to date	2017	Pre-construction
GAS DISTRIBUTION				
20. Greater Toronto Area Project	$0.7 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
21. Massif du Sud Wind Project	$0.2 billion	$0.2 billion	2013	Complete
22. Saint Robert Bellarmin Wind Project	$0.1 billion	$0.1 billion	2013	Complete
23. Lac Alfred Wind Project	$0.3 billion	$0.3 billion	2013 (in phases)	Complete
24. Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2013	Complete
25. Cabin Gas Plant	$0.8 billion	$0.8 billion	To be determined	Deferred
26. Pipestone and Sexsmith Project	$0.3 billion	$0.2 billion	2012-2014 (in phases)	Under construction
27. Tioga Lateral Pipeline	US$0.1 billion	US$0.1 billion	2013	Complete
28. Venice Condensate Stabilization Facility	US$0.1 billion	US$0.1 billion	2013	Complete
29. Blackspring Ridge Wind Project	$0.3 billion	$0.2 billion	2014	Under construction
30. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.2 billion	2014-2015 (in phases)	Under construction
31. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2015	Under construction
32. Keechi Wind Project	US$0.2 billion	No significant expenditures to date	2015	Under construction
33. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
SPONSORED INVESTMENTS				
34. EEP - Bakken Expansion Program	US$0.3 billion	US$0.3 billion	2013	Complete
35. The Fund - Bakken Expansion Program	$0.2 billion	$0.2 billion	2013	Complete
36. EEP - Berthold Rail Project	US$0.1 billion	US$0.1 billion	2013	Complete
37. EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.2 billion	2013	Complete
38. EEP - Bakken Access Program	US$0.1 billion	US$0.1 billion	2013	Complete
39. EEP - Texas Express NGL System	US$0.4 billion	US$0.4 billion	2013	Complete
40. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Under construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
41. EEP - Eastern Access[4]	US$2.6 billion	US$1.3 billion	2013-2016 (in phases)	Under construction
42. EEP - Lakehead System Mainline Expansion[4]	US$2.4 billion	US$0.2 billion	2014-2016 (in phases)	Under construction
43. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	No significant expenditures to date	2015	Pre-construction
44. EEP - Sandpiper Project	US$2.6 billion	US$0.1 billion	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 December 31, 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.*

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

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 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 in 2013 was curtailed due to constraints on third party takeaway facilities. A 105-kilometre (65-mile), 36-inch diameter pipeline lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P.'s (Enterprise) ECHO crude oil terminal (ECHO Terminal) in Houston, Texas was placed into service in January 2014 and is expected to relieve these constraints.

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 by mid-2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. Included in the project scope is the lateral from the Seaway Jones Creek facility southwest of Houston, Texas into the ECHO Terminal noted above.

In addition, a 137-kilometre (85-mile) pipeline will be constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining centre to provide shippers access to the region's heavy oil refining capabilities. This extension will provide capacity of 750,000 bpd and is now expected to be available in mid-2014.

Including the acquisition of the initial 50% interest, Enbridge's total expected cost for the Seaway Pipeline is approximately US$2.4 billion. The acquisition, reversal and expansion 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$1.8 billion.

Liquids Pipelines

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

Current Assets
Growth Opportunities

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 initial phase of the South Cheecham Rail and Truck Terminal (the Terminal), located approximately 75 kilometres (47 miles) southeast of Fort McMurray, Alberta. The Terminal, which is being 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 into 2014. 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. Construction of additional phases of the Terminal is under active consideration by the Company and Keyera.

Athabasca Pipeline Capacity Expansion
In December 2013, the Company completed the second phase of the expansion of its Athabasca Pipeline to its full capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The first phase of the expansion, which increased capacity to approximately 430,000 bpd, was completed and placed into service in March 2013. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta. The completed expansion will accommodate additional contractual commitments, including incremental production from the Christina Lake Oil Sands Project operated by Cenovus Energy Inc. (Cenovus). The total cost of the project was approximately $0.4 billion.

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 includes 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. The project is expected 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 terminalling 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 terminal scope of work was substantially completed in December 2013 and the overall system is expected to be available for service in the first quarter of 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. 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$1.6 billion.

On August 23, 2013, the Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court). The Complaint was filed against multiple federal agencies (the Defendants) and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. 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 and the Plaintiff's request for preliminary injunction was denied by the Court on November 13, 2013. A court hearing is scheduled for February 21, 2014 concerning the merits of the Complaint against the federal agencies.

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 National Energy Board (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 are expected to affect the Canadian Mainline Expansion. However, temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput from the delay. 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. (ConocoPhillips) and Total E&P Canada Ltd. (the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont's Phase 2 expansion. The Company is constructing two new 450,000 barrel blend tanks and converting an existing tank from blend to diluent service. The expansion is expected to come into service in two phases, with the blended product system expected in the fourth quarter of 2014 and the diluent system expected in the first quarter of 2015. The estimated cost of the project is approximately $0.3 billion with expenditures to date of approximately $0.1 billion.

Athabasca Pipeline Twinning

This project involves 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 $0.6 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 expected to enter service in 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 $0.2 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 and 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 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 49-kilometre (31-mile) 16-inch diameter pipeline from the AOC Hangingstone project site to Enbridge's existing Cheecham Terminal, and related facility modifications at Cheecham. Phase I of the project will provide an initial capacity of 16,000 bpd and is expected to be placed into service in 2015 at an estimated cost of approximately $0.1 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

Sunday Creek Terminal Expansion
In January 2014, the Company announced it will construct additional facilities at its Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands operated by Cenovus and jointly owned with ConocoPhillips. The expansion includes development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil work for a future tank. The existing Sunday Creek Terminal was put into service in August 2011. The estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion and a targeted in-service date of 2015.

Canadian Mainline System Terminal Flexibility and Connectivity
As part of the Light Oil Market Access Program initiative, the Company is undertaking the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The cost of the project is expected to be approximately $0.6 billion, with expenditures incurred to date of approximately $0.2 billion, and with varying completion dates from 2013 through 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 regulatory approval, Enbridge plans to construct a new 50-kilometre (31-mile) 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge's existing Cheecham Terminal. The project will provide capacity of 40,000 bpd at an estimated cost of approximately $0.1 billion and is expected to enter service in 2016.

Wood Buffalo Extension
In 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 will extend Enbridge's existing Wood Buffalo Pipeline and 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 Norlite, a new industry diluent pipeline to meet the needs of multiple producers in the Athabasca oil sands region. Under the currently envisioned scope, a 20-inch diameter pipeline with an approximate ultimate capacity of up to 280,000 bpd, depending on final scope and hydraulic design, will be anchored by throughput commitments from both the Fort Hills Partners for production from the proposed Fort Hills Project and from Suncor Partnership's proprietary oil sands production. Norlite will involve the construction of a new 489-kilometre (303-mile) pipeline from Enbridge's Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership's East Tank Farm, which is adjacent to Enbridge's existing Athabasca Terminal. If Enbridge is successful in securing additional long term commitments on the proposed Norlite system, the scope of the project could be increased to a 24-inch diameter pipeline system as well as include a potential lateral pipeline to Enbridge's Norealis Terminal. Subject to regulatory and other approvals, Norlite is expected to be completed in 2017 at an estimated cost of approximately $1.4 billion. If upsized to a 24-inch diameter pipeline, it will provide capacity to transport up to 270,000 bpd of diluent from Edmonton into the Athabasca oil sands region, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. Norlite 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.

GAS DISTRIBUTION
Greater Toronto Area Project

Gas Distribution
20 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 to continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.7 billion, the 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 approval was received from the OEB in January 2014. 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 development of the 150-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 PPA. Project construction was completed in December 2012 at a final investment by Enbridge of approximately $0.2 billion and commercial operation commenced in January 2013.

Saint Robert Bellarmin Wind Project

In July 2013, Enbridge acquired 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 was 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 during 2013 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

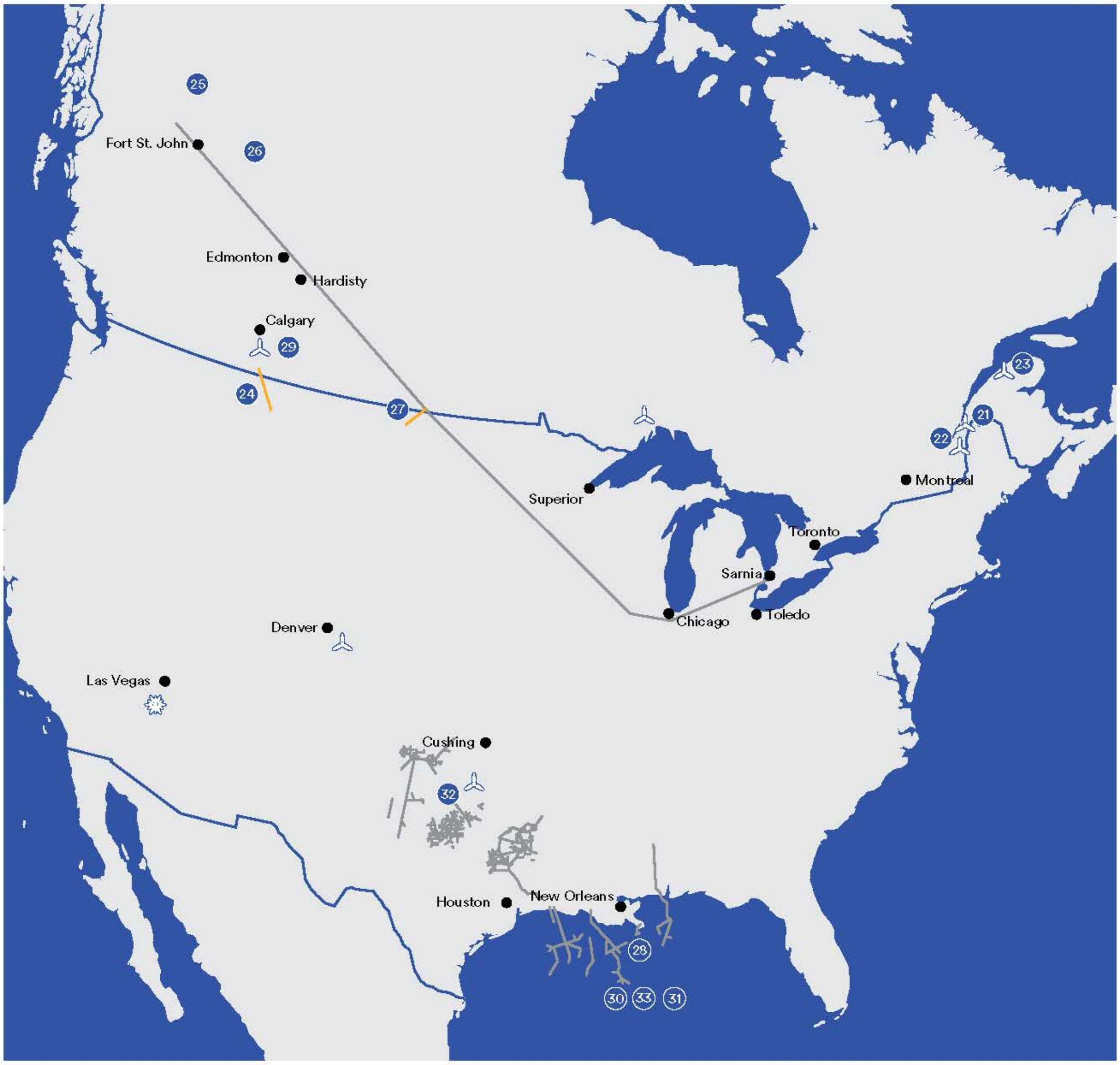
In September 2013, Enbridge completed and placed into service the first 300-MW phase of MATL. MATL is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and buoyant power demand in Alberta. Post-completion expenditures will continue to be incurred into 2014 and the estimated cost for the first phase of the project remains at approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. An expansion of an additional 300-MW of transmission capacity 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. Expenditures were incurred throughout 2013 to complete pre-commissioning construction on Phase 1 and to place Phase 2 into preservation mode. Under the deferral, the Company's total investment in phases 1 and 2 is approximately $0.8 billion. In December 2012, Enbridge started earning fees on its investment made to date in both phases 1 and 2. On May 1, 2013, the Company became operator of Cabin.

Pipestone and Sexsmith Project

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



Gas Pipelines, Processing and Energy Services

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Tioga Lateral Pipeline
In September 2013, Alliance Pipeline US completed construction and placed into-service a natural gas pipeline lateral and associated facilities to connect production from the Hess Corporation (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 will facilitate movement of liquids-rich natural gas to NGL processing facilities owned by Aux Sable near 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 share of the final cost of the project was approximately US$0.1 billion. In October 2012, Alliance Pipeline US executed a contract with Hess as an anchor shipper. Aux Sable and Hess reached a concurrent agreement for provision of NGL services.

Venice Condensate Stabilization Facility
In November 2013, the Company completed the expansion of the Venice Condensate Stabilization and Separation Facilities (Venice) at its Venice, Louisiana facility within Enbridge Offshore Pipelines (Offshore). The expansion increased the capacity of the stabilization facilities to approximately 12,500 barrels of condensate per day and the separation facilities to approximately 12,200 bpd. The project was completed at an approximate cost of US$0.1 billion. The expanded condensate stabilizing 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 the condensate will be separated from the gas and stabilized.

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 project, 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.

Walker Ridge Gas Gathering System
The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the WRGGS to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 100 mmcf/d. The Jack St. Malo portion of the WRGGS is expected to be placed into service in the third quarter of 2014 and the Big Foot Pipeline portion is now expected to be placed into service in the second quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.2 billion.

Big Foot Oil Pipeline
Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., Enbridge is constructing a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's undertaking of the WRGGS construction, discussed above. Upon completion of the project, Enbridge will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion, and is now expected to enter service in the second quarter of 2015 to align with the availability of production.

Keechi Wind Project
In January 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-MW Keechi project, located in Jack County, Texas, at an investment of approximately US$0.2 billion. RES Americas is constructing the wind project under a fixed price, engineering, procurement and construction agreement. Construction on the project commenced in December 2013, with expected completion in 2015. Upon attaining commercial operation, MetLife, Inc. will provide tax equity financing for the project. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year PPA with Microsoft Corporation.

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. 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 North Dakota 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 enhanced 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.

Sponsored Investments

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42 EEP - Lakehead System Mainline Expansion

43 EEP - Beckville Cryogenic Processing Facility

44 EEP - Sandpiper Project

Texas Express NGL System

In October 2013, EEP, Enterprise, Anadarko and DCP Midstream Partners, L.P. (DCP Midstream) announced that 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. EEP's total investment in the Texas Express NGL System was approximately US$0.4 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 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 a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by Enbridge include a reversal of its Line 9 and expansion of the Toledo Pipeline. Projects being undertaken by EEP include an expansion of its Line 5 and expansions of the United States mainline involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. The 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. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion. Subject to 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 $0.2 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.

In November 2013, EEP completed and placed into service the expansion of its Line 62 between Flanagan, Illinois and Griffith, Indiana. The Line 62 expansion increased capacity by 105,000 bpd. EEP is also replacing additional sections of Line 6B in Indiana and Michigan, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline are being replaced with 36-inch diameter pipe. The target in-service date for the Line 6B project is split into two phases, with the segment between Griffith and Stockbridge expected to be completed in the first quarter of 2014 and the segment from Ortonville, Michigan to Sarnia, Ontario expected to be completed in 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 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 at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. 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 projects being undertaken by EEP as part of the Eastern Access initiative including the United States mainline expansions, the Line 5 expansion and the Line 6B capacity expansion project, is approximately US$2.6 billion, with expenditures to date of approximately US$1.3 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. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and includes the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase includes an increase in capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. 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. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower and no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd, the target in-service dates for the proposed projects are the third quarter of 2014 for the initial phase and 2015 for the second phase. It is now anticipated that it will take longer to obtain regulatory approval than planned. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput.

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 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$0.2 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. Construction activities have commenced and the Beckville Plant is expected to be placed into service in 2015.

Sandpiper Project

As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The original proposed expansion would involve construction of a 965-kilometre (600-mile) 24-inch diameter line from Beaver Lodge Station near Tioga, 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 Tioga 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, with expenditures incurred to date of approximately US$0.1 billion.

In November 2013, EEP and Enbridge announced that Marathon Petroleum Corporation (MPC) had been secured as an anchor shipper for Sandpiper. As part of the arrangement, EEP, through its subsidiary, North Dakota Pipeline Company LLC (NDPC) (formerly known as Enbridge Pipelines (North Dakota) LLC), and Williston Basin PipeLine LLC (Williston), an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of Sandpiper construction and has the option to participate in other growth projects (not to exceed $1.2 billion in aggregate). As a result of Williston funding part of Sandpiper’s construction, Williston will obtain an approximate 27% equity interest in NDPC at the in service date of Sandpiper, targeted for early 2016.

A petition was filed with the Federal Energy Regulatory Commission (FERC) to approve recovery of Sandpiper's costs through a surcharge to the 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. Furthermore, in November 2013, EEP announced an open season to solicit commitments from shippers for capacity created by Sandpiper. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity identified above. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals, 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 significant additional attractive projects under development which have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

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

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

On December 19, 2013, the JRP issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living. The JRP found that the potential economic effects of Northern Gateway on local, regional, and national economics would be positive and would likely be significant. The JRP is also of the view that the Company's commitments break new ground by providing an unprecedented level of long-term economic, environmental, and social benefits to Aboriginal groups. It noted that the benefits of Northern Gateway outweigh its burdens and that "Canadians would be better off with the Enbridge Northern Gateway Project than without it."

The JRP found that Northern Gateway provided appropriate and effective opportunities for the public and potentially-affected parties to learn about the project and to provide their views and concerns to the Company. The JRP was satisfied that Northern Gateway considered, and was responsive to, the input it received regarding the design, construction, and operation of the project.

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

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

The JRP included an appendix with 209 conditions that the JRP recommended be included in any certificate that was issued.

The JRP recommended to the Governor in Council that certificates of public convenience and necessity for the oil and condensate pipelines, incorporating the terms and conditions in their report, be issued to Northern Gateway pursuant to Part III of the NEB Act. The Government of Canada will now consult with Aboriginal groups on the JRP report and its recommendations prior to making a decision on whether to direct the NEB to issue the certificates for the pipelines. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. The Governor in Council's decision is expected in June 2014.

The cost estimate included in the Northern Gateway filing with the JRP reflects a preliminary estimate prepared in 2004 and escalated to 2010. A detailed estimate based on full engineering analysis of the pipeline route and terminal location is currently being prepared. The detailed estimate will reflect a larger proportion of high cost terrain, longer tunnelling requirements and more extensive terminal site rock excavation than provided for in the preliminary estimate, which is expected to result in a significant increase in the cost estimate. The revised estimate is anticipated to be completed in the first quarter of 2014.

Five applications for judicial review have been filed with the Federal Court and the Federal Court of Appeal; three from Aboriginal groups and two from environmental groups. The applications seek to set aside the findings of the JRP and prohibit the Federal Government from taking any action to enable the project to proceed.

Subject to continued commercial support, regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service in 2018 at the earliest. The timing and outcome of judicial reviews could also impact the start of construction or other project activities, which may lead to a delay in the start of operations beyond the current forecast.

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

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

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 (bcf/d) of natural gas. The line would follow existing utility corridors to an interconnect in Michigan and utilize the existing Vector pipeline 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.

LIQUIDS PIPELINES

EARNINGS

	2013	2012	2011
(millions of Canadian dollars)			
Canadian Mainline	**460**	432	336
Regional Oil Sands System	**170**	110	111
Southern Lights Pipeline	**49**	42	41
Seaway Pipeline	**48**	24	(3)
Spearhead Pipeline	**31**	37	17
Feeder Pipelines and Other	**12**	10	(1)
Adjusted earnings	**770**	655	501
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(268)**	42	(48)
Canadian Mainline - Line 9 tolling adjustment	**-**	6	10
Canadian Mainline - shipper dispute settlement	**-**	-	14
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(56)**	-	-
Regional Oil Sands System - make-up rights adjustment	**(13)**	-	-
Regional Oil Sands System - make-up rights out-of-period adjustment	**(37)**	-	-
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**31**	-	-
Regional Oil Sands System - prior period adjustment	**-**	(6)	-
Regional Oil Sands System - asset impairment write-off	**-**	-	(8)
Spearhead Pipeline - changes in unrealized derivative fair value gains	**-**	-	1
Earnings attributable to common shareholders	**427**	697	470

Liquids Pipelines adjusted earnings were $770 million in 2013 compared with adjusted earnings of $655 million in 2012 and $501 million in 2011. The Company continued to realize growth on Canadian Mainline primarily from strong supply from western Canada and the ongoing effect of crude oil price differentials whereby demand for discounted crude by United States midwest refiners remained high and drove increases in throughput on the Canadian Mainline. New assets placed into service on Regional Oil Sands System and expanded available capacity on Seaway Pipeline also contributed to adjusted earnings growth.

Liquids Pipelines earnings were impacted by the following adjusting items:

- Canadian Mainline earnings for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage risk exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline earnings for 2012 and 2011 included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2011 included the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- Regional Oil Sands System earnings for 2013 included a charge related to the Line 37 crude oil release which occurred in June 2013. See *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release.*
- Regional Oil Sands System earnings for 2013 included an adjustment to recognize revenue for certain long-term take-or-pay contracts ratably over the contract life. Make-up rights are earned when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. Generally, under such take-or-pay contracts, payments are received ratably over the life of the contract as capacity is provided, regardless of volumes shipped, and are non-refundable. Should make-up rights be utilized in future periods, costs associated with such transportation service are typically passed through to shippers, such that little or no cost is borne by Enbridge. As such, adjusted earnings reflect contributions from these contracts ratably over the life of the contract, consistent with contractual cash payments under the contract.
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to defer revenues associated with make-up rights earned under certain long-term take-or-pay contracts.
- Regional Oil Sands System earnings for 2013 included an out-of-period, non-cash adjustment to correct deferred income tax expense and to correct the rate at which deemed taxes are recovered under a long-term contract.
- Regional Oil Sands System earnings for 2012 included a revenue recognition adjustment related to prior periods.
- Regional Oil Sands System earnings for 2011 included the write-off of development expenditures on certain project assets.
- Spearhead Pipeline earnings for 2011 included unrealized fair value gains on derivative financial instruments used to manage exposures to allowance oil commodity prices.

CANADIAN MAINLINE

The mainline system is comprised of Canadian Mainline and the Lakehead System (the portion of the mainline in the United States that is managed by Enbridge through its subsidiaries). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines, with a combined design operating capacity of approximately 2.5 million bpd, which cross the Canada/United States border near Gretna, Manitoba and Neche, North Dakota, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included in Canadian Mainline are two crude oil pipelines and one refined products pipeline located in eastern Canada.

Competitive Toll Settlement

Canadian Mainline tolls are governed by the 10-year settlement reached between Enbridge and shippers on its mainline system and approved by the NEB in 2011. The CTS, which took effect on July 1, 2011, covers local tolls to be charged for service on the mainline system (with the exception of Lines 8 and 9). Under the terms of the CTS, the initial Canadian Local Toll (CLT), applicable to deliveries within western

Canada, was based on the 2011 Incentive Tolling Settlement (ITS) toll, subsequently adjusted by 75% of the Canada Gross Domestic Product at Market Price Index on July 1 of each year.

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

In limited circumstances the shippers or Enbridge may elect to renegotiate the toll. If a renegotiation of the toll is triggered, Enbridge and the shippers will meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the event.

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

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

Incentive Tolling

Prior to the CTS taking effect on July 1, 2011, tolls on Canadian Mainline were governed by various agreements which were subject to NEB approval. These agreements included both the 2011 and 2010 ITS applicable to the Canadian Mainline (excluding Lines 8 and 9), the Terrace agreement, the SEP II Risk Sharing agreement, the Alberta Clipper agreement and the Southern Access Expansion agreement which were recovered via the Mainline Expansion Toll.

Results of Operations

Canadian Mainline adjusted earnings were $460 million for the year ended December 31, 2013 compared with $432 million for the year ended December 31, 2012 and $336 million for the year ended December 31, 2011. The adjusted earnings increase was primarily driven by higher throughput from steady production from the oil sands in Alberta priced at levels which displaced other non-Canadian production from the midwest market and drove increased long-haul barrels on Canadian Mainline. Further volume growth on Canadian Mainline was limited towards the latter half of 2013 due to longer than expected refinery shutdowns and the delay in the start-up of a refinery conversion to heavy oil. The tempered growth in demand from refineries is expected to persist during the first quarter of 2014.

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

The comparability of Canadian Mainline earnings between 2012 and 2011 is affected by the change in tolling methodology. As noted previously, from July 1, 2011 onward, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS, whereas operations for the first six months of 2011 were governed by a series of agreements, the most significant being the ITS applicable to the mainline system and the Terrace and Alberta Clipper agreements.

Canadian Mainline revenues for the year ended December 31, 2012 reflected increased volumes and a higher Canadian Mainline IJT Residual Benchmark Toll. Volume throughput in 2012 was impacted by market conditions as incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota bolstered supply to midwest markets and placed increased downward pressure on crude oil prices in that market. This discounted crude oil, coupled with strong refining margins, increased demand in the midwest for Canadian and Bakken crude oil supply and drove increased long haul barrels on Canadian Mainline and EEP's Lakehead System. However, during the fourth quarter of 2012, Canadian Mainline was not able to capture the full throughput benefit of the increased supply available to it due to capacity limitations which arose from pressure restrictions being applied to certain lines pending completion of inspection and repair programs. An increase in operating and administrative costs, primarily due to higher employee related costs and higher leak remediation costs, also impacted 2012 adjusted earnings.

Supplemental information on Canadian Mainline adjusted earnings for the years ended December 31, 2013 and 2012 and for the six month period from July 1, 2011, the effective date of the CTS, to December 31, 2011 are as follows:

	Year ended December 31,		Six months ended December 31,
	2013	2012	2011
(millions of Canadian dollars)			
Revenues	**1,434**	1,367	618
Expenses			
Operating and administrative	**407**	382	194
Power	**122**	112	54
Depreciation and amortization	**244**	219	104
	773	713	352
	661	654	266
Other income/(expense)	**3**	(4)	5
Interest expense	**(162)**	(131)	(66)
	502	519	205
Income taxes	**(42)**	(87)	(31)
Adjusted earnings	**460**	432	174
Effective United States to Canadian dollar exchange rate[1]	**0.999**	0.971	0.972

December 31,	**2013**	2012	2011
(United States dollars per barrel)			
IJT Benchmark Toll[2]	**$3.98**	$3.94	$3.85
Lakehead System Local Toll[3]	**$2.18**	$1.85	$2.01
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.80**	$2.09	$1.84

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.*

Throughput Volume[1]

	Q1	Q2	Q3	Q4	Total
2013	**1,783**	**1,604**	**1,736**	**1,827**	**1,737**
2012	1,687	1,659	1,617	1,622	1,646
2011	1,602	1,457	1,565	1,594	1,554

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

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

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

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

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

Canadian Mainline income taxes reflect current income taxes only. Under the CTS, the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to deferred income taxes is recognized as incurred.

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

Prior to the implementation of the CTS, revenues on the Canadian Mainline were recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting. The Company discontinued the application of rate-regulated accounting to its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis commencing July 1, 2011. A regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance continued to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods was being recovered through a surcharge to the CLT and IJT.

REGIONAL OIL SANDS SYSTEM

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

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, which links the Athabasca oil sands in the Fort McMurray region to a pipeline hub at Hardisty, Alberta. In March 2013, the Athabasca Pipeline's capacity was increased to 430,000 bpd and in December 2013 was further expanded to 570,000 bpd, depending on the viscosity of crude being shipped. The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenues are recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered service in 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge's Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline had an initial design capacity, dependent on crude slate, of up to 350,000 bpd. The pipeline was further expanded to 415,000 bpd in the fourth quarter of 2012 and can ultimately be expanded to 600,000 bpd. Enbridge has a long-term (25-year) take-or-pay commitment with multiple shippers on the Waupisoo Pipeline who collectively have contracted for approximately three-quarters of the capacity.

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

Results of Operations

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

Adjusted earnings for the year ended December 31, 2012 were $110 million compared with $111 million for the year ended December 31, 2011. Higher shipped volumes and increased tolls on certain laterals, and higher earnings from an annual escalation in storage and terminalling fees were more than offset by higher operating and administrative expense, and higher depreciation expense. Adjusted earnings for 2012 also included contributions from new regional infrastructure, the Woodland and Wood Buffalo pipelines, placed into service in the fourth quarter of 2012, although offset by a lack of earnings from assets sold to the Fund in December 2012.

Line 37 Crude Oil Release

On June 22, 2013, Enbridge reported a release of light synthetic crude oil on its Line 37 pipeline approximately two kilometres north of Enbridge's Cheecham Terminal, 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 was recovered and on July 11, 2013 Line 37 returned to service at reduced operating pressure. Normal operating pressure was restored on Line 37 on July 29, 2013 after finalization of geotechnical analysis.

As a precaution, on June 22, 2013 the Company shut down the pipelines that share a corridor with Line 37, including the Athabasca, Waupisoo, Wood Buffalo and Woodland pipelines. 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 $56 million after-tax and before insurance recoveries. 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.

SOUTHERN LIGHTS PIPELINE
The 180,000 bpd, 20-inch diameter Southern Lights Pipeline was placed into service on July 1, 2010 transporting diluent from Chicago, Illinois to Edmonton, Alberta. Enbridge receives tariff revenues under long-term contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus a return on equity (ROE) of 10%. Uncommitted volumes, up to a specified amount, generate tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers.

Results of Operations
Southern Lights earnings increased to $49 million for the year ended December 31, 2013 compared with $42 million for the year ended December 31, 2012 and $41 million for the year ended December 31, 2011 primarily due to higher recovery of negotiated depreciation rates in 2013 transportation tolls.

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

The reversal of the Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast, 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 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, completed in January 2014, is expected to eliminate these constraints. Spot volumes on Seaway Pipeline can also be impacted by the spread between WTI and Louisiana Light Sweet crude oil prices.

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

Results of Operations

Seaway Pipeline earnings for the year ended December 31, 2013 were $48 million compared with earnings of $24 million for the year ended December 31, 2012. The higher contribution reflected a full year of operations and incremental available capacity on the pipeline in 2013. The Seaway Pipeline reversal 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. As noted above, actual throughput experienced in 2013 was curtailed due to constraints on third party takeaway facilities and during the latter part of the year due to loss of spot volume shipments as a result of a lower spread between crude oil prices at Cushing, Oklahoma and the Gulf Coast. These takeaway constraints are anticipated to be relieved in the first quarter of 2014. Partially offsetting the earnings increase was higher financing costs and higher depreciation expense from an increased asset base.

Seaway Pipeline earnings for the year ended December 31, 2012 were $24 million and reflected preliminary service at an approximate capacity of 150,000 bpd which commenced in May 2012. The $3 million loss recognized for the year ended December 31, 2011 was related to early stage business development costs that were not eligible for capitalization.

SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from the Flanagan, Illinois delivery point of the Lakehead System to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and an expansion was completed in May 2009, increasing capacity from 125,000 bpd to 193,300 bpd.

Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead. Both the initial committed shippers and expansion shippers were required to enter into 10-year shipping commitments at negotiated rates that were offered during the open season process. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.

Results of Operations

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

Spearhead Pipeline adjusted earnings were $37 million for the year ended December 31, 2012 compared with $17 million for the year ended December 31, 2011. Spearhead Pipeline adjusted earnings increased as a result of higher volumes and tolls, partially offset by higher operating and administrative costs, including power and repairs and maintenance. Volumes significantly increased over 2011 due to higher commodity price differentials which increased demand at Cushing, Oklahoma in anticipation of additional capacity on the Seaway Pipeline for further transportation to the Gulf Coast.

FEEDER PIPELINES AND OTHER

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

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

Results of Operations

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

In 2012, Feeder Pipelines and Other earnings were $10 million compared with a loss of $1 million for the year ended December 31, 2011. The increase in earnings was primarily a result of a higher contribution from Olympic due to a tariff increase, higher volumes on Toledo Pipeline and increased terminalling fees. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP's Lakehead System.

BUSINESS RISKS

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

Asset Utilization

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

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

Enbridge seeks to mitigate utilization risks within its control. The market access and expansion projects under development are expected to reduce capacity bottlenecks and introduce new markets for customers. Liquids Pipelines also works with the shipper community to enhance scheduling efficiency and communications as well as makes continuous improvements to scheduling models and timelines to alleviate pipeline restrictions. Throughput risk is also partially mitigated by provisions in the CTS agreement, which allows Enbridge to negotiate an amendment to the agreement in the event certain minimum threshold volumes are not met.

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

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

The Company's liquids pipelines also face economic regulatory risk. Broadly defined, economic regulation risk is the risk regulators or other government entities change or reject proposed or existing commercial arrangements. The Canadian Mainline and other liquids pipelines are subject to the actions of various regulators, including the NEB and the FERC, with respect to the tariffs and tolls of those operations. The changing or rejecting of commercial arrangements could have an adverse effect on the Company's revenues and earnings. The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers which govern the majority of the segment's assets and the involvement of its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations; however, the risk that a regulator could overturn long-term agreements between the Company and shippers continues to exist.

Competition
Competition may result in a reduction in demand for the Company's services, fewer new project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition also arises from existing and proposed pipelines that provide, or are proposed to provide, access to market areas currently served by the Company's liquids pipelines, such as proposed projects expected to serve the Gulf Coast or eastern markets, as well as from proposed projects in the Alberta regional oil sands market. Additionally, crude oil price differentials and the long lead-times required to build new pipeline capacity continues to make transportation of crude oil by rail competitive where railways are able to access markets not currently serviced by pipelines.

The Company believes that its liquids pipelines continue to provide attractive options to producers in the WCSB due to its competitive tolls and flexibility through its multiple delivery and storage points. Enbridge's current complement of growth projects to expand market access and its commitment to project execution is expected to further provide shippers reliable and long-term competitive solutions for oil transportation. The Company's existing right-of-way for the Canadian Mainline also provides a competitive advantage as it can be difficult and costly to obtain rights of way for new pipelines traversing new areas.

Foreign Exchange and Interest Rate Risk
The CTS agreement for the Canadian Mainline exposes the Company to risks related to movements in foreign exchange rates and interest rates. Foreign exchange risk arises as the Company's IJT under the

CTS is charged in United States dollars. These risks have been substantially managed through the Company's hedging program by using financial contracts to fix the prices of United States dollars and interest rates. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, the Company's earnings are exposed to associated changes in the mark-to-market value of these contracts.

GAS DISTRIBUTION

EARNINGS

	2013	2012	2011
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc. (EGD)	**156**	149	135
Other Gas Distribution and Storage	**20**	27	38
Adjusted earnings	**176**	176	173
EGD - gas transportation costs out-of-period adjustment	**(56)**	-	-
EGD - (warmer)/colder than normal weather	**9**	(23)	1
EGD - tax rate changes	**-**	(9)	-
EGD - recognition of regulatory asset	**-**	63	-
Other Gas Distribution and Storage - regulatory deferral write-off	**-**	-	(262)
Earnings/(loss) attributable to common shareholders	**129**	207	(88)

Adjusted earnings from Gas Distribution were $176 million for the year ended December 31, 2013 compared with $176 million for 2012 and $173 million for the year ended December 31, 2011. 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. EGD adjusted earnings growth reflected the positive impacts of a larger customer base and the absence of earnings sharing with natural gas customers under the one year cost of service settlement. In 2012, adjusted earnings from Other Gas Distribution and Storage were negatively impacted compared with the prior year due to changes in rate setting methodology applicable to gas distribution operations in New Brunswick.

Gas Distribution earnings were impacted by the following adjusting items:

- EGD earnings for 2013 reflected an out-of-period correction to gas transportation costs which had previously been deferred.
- EGD earnings for all periods were adjusted to reflect the impact of weather.
- EGD earnings for 2012 reflected the impact of unfavourable tax rate changes on deferred income tax liabilities.
- EGD earnings for 2012 included the recognition of a regulatory asset related to recovery of other postretirement benefit obligations (OPEB) costs pursuant to an OEB rate order. See *Gas Distribution – Enbridge Gas Distribution Inc. – Rate Application*.
- Other Gas Distribution and Storage earnings for 2011 reflected the discontinuation of rate-regulated accounting for Enbridge Gas New Brunswick Inc. (EGNB) and the related write-off of a deferred regulatory asset and certain capitalized operating costs, net of tax. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Inc. – Regulatory Matters*.

ENBRIDGE GAS DISTRIBUTION INC.

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

Rate Application
EGD's rates for 2013 were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed ROE. The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories.

Prior to 2013, EGD operated under a revenue cap IR mechanism, calculated on a revenue per customer basis, with the OEB for a five-year period between 2008 and 2012. Under the IR mechanism, the Company was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis. The earnings sharing mechanism resulted in the return of revenue to customers of $10 million for the year ended December 31, 2012 and $13 million for the year ended December 31, 2011. The earnings sharing mechanism, which was previously in effect under IR, did not apply to the 2013 Settlement.

The 2013 Settlement established the right to recover an existing OPEB liability of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

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

- reduce regulatory costs with less frequent hearings;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide for necessary infrastructure upgrades and safety and reliability projects.

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

Adjusted earnings for the year ended December 31, 2012 were $149 million compared with $135 million for the year ended December 31, 2011. The increase in EGD's adjusted earnings was primarily due to customer growth, favourable rate variances and higher pipeline capacity optimization. This growth was partially offset by an increase in system integrity and safety-related costs and higher employee costs, as well as higher depreciation due to a higher in-service asset base.

OTHER GAS DISTRIBUTION AND STORAGE
Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being EGNB (100% owned and operated by the Company), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB has approximately 11,000 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

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

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

The Company commenced legal proceedings against the Government of New Brunswick, seeking damages for breach of contract, in April 2012. The Company also commenced a separate application to the New Brunswick Court of Queen's Bench to quash the Government's rates and tariffs regulation in May 2012. The Company's application was initially dismissed, but on appeal it was ultimately successful, in part. The Court of Appeal ruled that the part of the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor-in-Council. The Court of Appeal upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. As a result of this outcome, EGNB applied on June 14, 2013 to the EUB for new rates, effective July 1, 2013, for commercial and industrial customers. On July 26, 2013, the EUB granted EGNB's application for new rates, but with an effective date of August 1, 2013. The EUB's decision enabled EGNB to fully recover its revenue requirement from August 1, 2013 until the next rate period. 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, and a decision is expected in the first quarter of 2014.

On February 4, 2014, EGNB commenced a further legal proceeding against the Government of New Brunswick. The action seeks damages for improper extinguishment of the deferred regulatory asset that was previously eliminated from EGNB's Consolidated Statements of Financial Position, as discussed above. There is no assurance that any of EGNB's legal proceedings against the Province of New Brunswick will be successful or will result in any recovery.

Results of Operations

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

Other Gas Distribution and Storage adjusted earnings were $27 million for the year ended December 31, 2012 compared with $38 million for the year ended December 31, 2011. This adjusted earnings decrease was primarily due to the change in rate setting methodology applicable to EGNB enacted in 2012. Effective January 1, 2012, the discontinuance of rate-regulated accounting at EGNB resulted in earnings subject to increased variability, including quarterly seasonality, as there was no further accumulation of the regulatory deferral account. Earnings for 2012 were impacted by lower volume due to a decrease in demand for natural gas, which was the result of a warmer than normal winter.

BUSINESS RISKS

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

Economic Regulation

The utility operations of Gas Distribution are regulated by the OEB and EUB among others. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which Gas Distribution operates. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded. The Company seeks to mitigate economic regulation risk by maintaining regular and transparent communication with regulators and interveners on rate negotiations. The terms of rate negotiations are also reviewed by the Company's legal, regulatory and finance teams. Specific to the 2014 IR plan negotiations, the Company has used Alternate Dispute Resolution process when negotiating with the regulators and interveners in order to minimize more costly and time consuming formal hearings.

Natural Gas Cost Risk
EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB for inclusion in distribution rates. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and may request interim rate relief to recover or refund the natural gas cost differential. While the cost of natural gas does not impact EGD's earnings, it does affect the amount of EGD's investment in gas in storage. EGNB is also subject to natural gas cost risk as increases in natural gas prices that cannot be charged to customers could negatively impact earnings.

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

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

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

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

EARNINGS

	2013	2012	2011
(millions of Canadian dollars)			
Aux Sable	**49**	68	55
Energy Services	**75**	40	56
Alliance Pipeline US	**43**	39	39
Vector Pipeline	**22**	22	23
Enbridge Offshore Pipelines (Offshore)	**(2)**	(3)	(7)
Other	**16**	10	14
Adjusted earnings	**203**	176	180
Aux Sable - changes in unrealized derivative fair value gains/(loss)	**-**	10	(7)
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(206)**	(537)	125
Offshore - asset impairment loss	**-**	(105)	-
Other - changes in unrealized derivative fair value gains/(loss)	**(61)**	-	24
Earnings/(loss) attributable to common shareholders	**(64)**	(456)	322

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $203 million for the year ended December 31, 2013 compared with $176 million for the year ended December 31, 2012 and $180 million for the year ended December 31, 2011. Changing market conditions has resulted in variability in earnings for this segment as lower fractionation margins in 2013 resulted in lower contributions from Aux Sable, while favourable market conditions gave rise to greater margin opportunities in Energy Services in 2013. The increase in earnings in 2013 compared with 2012 also reflected contributions from additional natural gas midstream and renewable energy investments.

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

- Aux Sable earnings for 2012 and 2011 period reflected changes in the fair value of unrealized derivative financial instruments related to the Company's forward gas processing risk management position.
- Energy Services earnings/(loss) for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory. 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.
- Offshore loss for 2012 was impacted by an asset impairment loss related to certain of its assets, predominantly located within the Stingray and Garden Banks corridors. See *Gas Pipelines, Processing and Energy Services – Enbridge Offshore Pipelines – Asset Impairment* for further details.
- Other earnings/(loss) for 2013 and 2011 reflected changes in unrealized fair value gains or losses 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.

AUX SABLE

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

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

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

Aux Sable Canada has contracted capacity of the Septimus Pipeline and the Septimus Gas Plant to a producer under a 10-year take-or-pay contract which provides for a return on and of invested capital. Actual operating costs are recovered from the producer. In 2013, the majority of capacity at the Palermo Gas Plant and the Prairie Rose Pipeline was contracted to producers under take-or-pay contracts. Several producers' contract commitments decline over the next few years while certain producer contract commitments continue through 2020 under long-term take or pay contracts or with life-of-lease reserve dedication. Additional revenues are earned by Aux Sable based on a sharing of available NGL margin with producers.

Results of Operations

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

Aux Sable adjusted earnings were $68 million for the year ended December 31, 2012 compared with $55 million for the year ended December 31, 2011. Adjusted earnings increased primarily due to higher realized fractionation margins and earnings contributions from the Prairie Rose Pipeline and the Palermo Conditioning Plant acquired in July 2011.

Business Risks

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

Commodity Price Risk

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

Asset Utilization

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

ENERGY SERVICES

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy. This business transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company focused on capturing value from quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Any commodity price exposure created from this physical business is closely monitored and must comply with the Company's formal risk management policies.

Tidal Energy also provides natural gas marketing services, including marketing natural gas to optimize commitments on certain natural gas pipelines. To the extent transportation costs exceed the basis (location) differential, earnings will be negatively affected. Tidal Energy also provides natural gas supply, transportation, balancing and storage for third parties, leveraging its natural gas marketing expertise and access to transportation capacity.

Results of Operations

Energy Services adjusted earnings were $75 million for the year ended December 31, 2013, an increase over adjusted earnings of $40 million for the year ended December 31, 2012. Adjusted earnings from Energy Services are dependent on market conditions, including but not limited to, quality, time and location differentials, and results achieved in one period may not be indicative of results to be achieved in future periods. Dependency on market conditions was evident in the trend in quarterly earnings compared with the prior year whereby wide location and crude grade differentials gave rise to a greater number of and more profitable margin opportunities during the first half of 2013. These physical marketing opportunities began to diminish in the third quarter and culminated in a fourth quarter adjusted loss for Energy Services. Market conditions contributing to the fourth quarter adjusted loss included physical constraints which limited physical movement of barrels, such as pipeline apportionment and refinery outages, narrowing location spreads among markets physically accessed by Tidal Energy's committed transportation capacity and narrowing grade differentials which limit tank management opportunities. Although profitability declined in most lines of business, the fourth quarter loss primarily related to losses realized on financial contracts intended to hedge the value of committed physical transportation capacity, but which were not effective in doing so in the last three months of the year.

Energy Services adjusted earnings decreased from $56 million for the year ended December 31, 2011 to $40 million for the year ended December 31, 2012. The decline was primarily due to changing market conditions which gave rise to fewer margin opportunities in crude oil and NGL marketing.

Business Risks

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

Commodity Price Risk

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

Competition

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

ALLIANCE PIPELINE US

The Alliance System, which includes both the Canadian and United States portions of the pipeline system, consists of approximately 3,000 kilometres (1,864 miles) of integrated, high-pressure natural gas transmission pipeline and approximately 860 kilometres (534 miles) of lateral pipelines and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have firm service shipping contract capacity to deliver 1.466 bcf/d and 1.325 bcf/d, respectively. Enbridge owns 50% of Alliance Pipeline US, while the Fund, described under *Sponsored Investments*, owns 50% of Alliance Pipeline Canada.

Alliance connects with the Aux Sable NGL extraction and fractionation plant. Natural gas transported on Alliance downstream of the Aux Sable plant can be delivered to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and eastern United States and eastern Canada.

Alliance Pipeline US runs adjacent to the Bakken oil formation in North Dakota which offers new incremental sources of liquids-rich natural gas for delivery to downstream markets. In February 2010, a new receipt point on the pipeline near Towner, North Dakota was placed into service. The receipt point connects to the Prairie Rose Pipeline and provides shippers operating out of the Bakken access to Alliance. In September 2013, Alliance Pipeline US completed construction of the Tioga Lateral which will facilitate delivery of natural gas from Hess' Tioga field processing plant in the Bakken to downstream markets.

Transportation Contracts

Alliance Pipeline US has long-term, take-or-pay contracts to transport substantially all its 1.466 bcf/d of natural gas capacity. These contracts permit Alliance Pipeline US, whose operations are regulated by the FERC, to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 10.9%.

Alliance Pipeline US is in discussions with the shipper community regarding its service offerings post the December 2015 expiry of the majority of existing contracts.

Results of Operations

Alliance Pipeline US earnings were $43 million for the year ended December 31, 2013 compared with earnings of $39 million for each of the years ended December 31, 2012 and 2011. The increase in earnings in 2013 compared with 2012 reflected an increase in depreciation expense recovered through tolls and earnings related to the Tioga Lateral Pipeline which was placed into service in 2013.

VECTOR PIPELINE

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

Transportation Contracts
The total long haul capacity of Vector is approximately 87% committed through November 2015. Approximately 55% of the long haul capacity is committed through firm negotiated rate transportation contracts with shippers and approved by the FERC, while the remaining committed capacity is sold at market rates.

In December 2013, shippers under negotiated rate transportation contracts which represent 20% of the system's long haul capacity elected to extend their commitments beyond December 1, 2016 and preserve the option to extend their contracts on an annual basis. Vector is entitled to additional compensation from shippers that terminate their contracts prior to the November 30, 2020 expiry date.

Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector is an interstate natural gas pipeline with FERC and NEB approved tariffs that establish the rates, terms and conditions governing its service to customers. On the United States portion of Vector, maximum tariff rates are determined using a cost of service methodology and maximum tariff changes may only be implemented upon approval by the FERC. For 2013, the FERC approved maximum tariff rates included an underlying weighted average after-tax ROE component of 11.2%. On the Canadian portion, Vector is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2013, maximum tolls include an ROE component of 10.5% after-tax.

Results of Operations
Vector earnings were $22 million for the year ended December 31, 2013, comparable with $22 million for the year ended December 31, 2012 and $23 million for the year ended December 31, 2011, respectively, and reflected the stable, cost of service commercial arrangement in place for these years.

BUSINESS RISKS
The risks identified below are specific to both Alliance Pipeline US and Vector. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization
Currently, natural gas pipeline capacity out of the WCSB exceeds supply, due to the low price of natural gas and increased production from new shale gas developments. Alliance Pipeline US and Vector have been unaffected by this excess supply environment to date mainly because of long-term capacity contracts extending primarily to 2015. However, excess supply and depressed natural gas prices have led to a reduction or deferral of investment in upstream gas development, and could negatively impact re-contracting beyond this term. Additionally, increased supply from new shale developments including the Marcellus shale formation, which is among the largest gas plays in North America, could displace gas from the WCSB to the United States midwest further increasing re-contracting risk.

The re-contracting risk is somewhat mitigated as the Alliance System is well positioned to deliver incremental liquids-rich gas production from developments in the Montney and Bakken regions to the Aux Sable NGL extraction and fractionation plant. The Alliance System is also engaged with market participants in developing new receipt facilities and services to expand its reach in transporting liquids-rich gas to premium markets.

Competition
Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects to transport gas from existing and new gas developments. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance Pipeline US because of location, facilities or other factors. In addition, these pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of forcing

Alliance Pipeline US to realize lower revenues and cash flows. The ability of Alliance Pipeline US to cost-effectively transport liquids-rich gas serves to enhance its competitive position.

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

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

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

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

ENBRIDGE OFFSHORE PIPELINES
Offshore is comprised of 13 active natural gas gathering and FERC-regulated transmission pipelines and one active oil pipeline with a capacity of 60,000 bpd, in five major corridors in the Gulf of Mexico, extending to deepwater developments. These pipelines include almost 2,600 kilometres (1,600 miles) of underwater pipe and onshore facilities with total capacity of approximately 7.3 bcf/d. Offshore currently moves approximately 45% of offshore deepwater gas production through its systems in the Gulf of Mexico.

Transportation Contracts
The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), over the expected production life. Some contracts have minimum throughput volumes which are subject to ship-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current delivery expectations. The majority of long-term transport rates are market-based, with revenue generation directly tied to actual production deliveries. Some of the systems operate under a cost-of-service methodology, including certain lines under FERC regulation.

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

Asset Impairment

In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas in the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

Results of Operations

For the year ended December 31, 2013, Offshore incurred an adjusted loss of $2 million compared with an adjusted loss of $3 million for the year ended December 31, 2012. Positive factors impacting the change in Offshore earnings included the Venice expansion placed into service in November 2013, cost savings achieved from the Company's election not to renew windstorm insurance coverage and lower depreciation expense. However, more than offsetting these positive factors were persistent weak volumes on the majority of Offshore's pipelines due to decreased production in the Gulf of Mexico. The challenging market conditions which impacted Offshore in 2013 is expected to persist and be a drag on Offshore earnings until such time as the WRGGS and Big Foot Pipeline are placed into service, which are expected to occur in the third quarter of 2014 and the second quarter of 2015, respectively.

For the year ended December 31, 2012, Offshore incurred an adjusted loss of $3 million compared with a loss of $7 million for the year ended December 31, 2011. Offshore realized losses due to weak volumes from delayed drilling programs and scheduled production outages by producers in the Gulf of Mexico. The decrease in loss year-over-year resulted from a higher transportation rate for volumes shipped on the Stingray Pipeline System, a reduction in interest expense and a $2 million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011.

Business Risks

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

Asset Utilization

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

Competition

There is competition for new and existing business in the Gulf of Mexico, with an increasing number of competitors willing to construct and operate production host platforms for future deepwater prospects. Offshore has been able to capture key opportunities, allowing it to more fully utilize existing capacity. Offshore's gas pipelines serve a majority of the strategically located deepwater host platforms, positioning it favourably to make incremental investments for new platform connections and receive additional transportation volumes from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the planned Big Foot and Heidelberg pipelines. Given rates of decline, offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico. Competing developments may impact the ability of the Company to recover its investment in long-lived offshore assets.

Natural Disaster Incidents

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

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

OTHER

Other includes interests in approximately 1,250 MW of the enterprise-wide portfolio of 1,800 MW of renewable power generating assets. The balance of the portfolio is held by the Fund. Of the interests presented within Other, 830 MW represents active production from four wind farms and one solar asset while the remainder represents interests in growth projects under construction. Also included in Other is MATL, the Company's first power transmission asset, and its natural gas midstream business, including Cabin located in northeastern British Columbia.

To optimize funding of its enterprise-wide slate of growth projects, Enbridge may drop down assets to its Sponsored Investments. In 2012, Greenwich Wind Energy Project (Greenwich), Amherstburg Solar Project (Amherstburg) and Tilbury Solar Project (Tilbury) were transferred to the Fund, following the 2011 transfer of the Ontario Wind, Sarnia Solar and Talbot Wind energy projects. Earnings contributions from these assets, net of noncontrolling interests, are reflected within Sponsored Investments from the date the assets were transferred to the Fund. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers.*

Results of Operations

Adjusted earnings from Other for the year ended December 31, 2013 were $16 million compared with $10 million for the year ended December 31, 2012. Higher earnings were mainly attributable to the commissioning of Lac Alfred and contributions from fees earned on the Company's investment in Cabin, for which earnings recognition commenced in December 2012. 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 (Cedar Point) due to lower wind resources.

Other adjusted earnings for the year ended December 31, 2012 were $10 million compared with $14 million for the year ended December 31, 2011. The decrease in adjusted earnings was primarily due to the sale of Ontario Wind, Sarnia Solar and Talbot Wind energy projects to the Fund in October 2011, followed by the sale of Greenwich, Amherstburg and Tilbury to the Fund in December 2012. Higher business development costs also contributed to the decrease in adjusted earnings. Partially offsetting this increase were the contributions from Cedar Point and Greenwich, which were commissioned in late 2011, and Silver State North Solar Project (Silver State) which was commissioned in early 2012.

SPONSORED INVESTMENTS

EARNINGS

	2013	2012	2011
(millions of Canadian dollars)			
Enbridge Energy Partners, L.P. (EEP)	**165**	141	151
Enbridge Energy, Limited Partnership (EELP)	**38**	38	42
Enbridge Income Fund (the Fund)	**110**	85	50
Adjusted earnings	**313**	264	243
EEP - leak insurance recoveries	**6**	24	50
EEP - leak remediation costs	**(44)**	(9)	(33)
EEP - changes in unrealized derivative fair value gains/(loss)	**(6)**	(2)	3
EEP - tax rate differences/changes	**(3)**	-	-
EEP - gain on sale of non-core assets	**2**	-	-
EEP - NGL trucking and marketing investigation costs	**-**	(1)	(3)
EEP - prior period adjustment	**-**	7	-
EEP - shipper dispute settlement	**-**	-	8
EEP - lawsuit settlement	**-**	-	1
EEP - impact of unusual weather conditions	**-**	-	(1)
Earnings attributable to common shareholders	**268**	283	268

Adjusted earnings from Sponsored Investments were $313 million for the year ended December 31, 2013 compared with $264 million for the year ended December 31, 2012 and $243 million for the year ended December 31, 2011. The increase in adjusted earnings resulted from increased contributions from the Fund following the transfer of certain renewable energy and crude oil storage assets from Enbridge and its wholly-owned subsidiaries in late 2012 and late 2011. EEP also contributed to the 2013 increase in year-over-year adjusted earnings primarily due to Enbridge's investment in preferred units of EEP issued in 2013, as well as higher incentive distributions.

Sponsored Investment earnings were impacted by the following adjusting items:

- EEP earnings for each period included insurance recoveries associated with the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases*.
- EEP earnings for each period included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Line 14 Crude Oil Release* and *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B 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 2013 included a gain on sale from non-core assets.
- EEP earnings for 2012 and 2011 reflected charges for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.
- EEP earnings for 2012 reflected a non-recurring out-of-period adjustment.
- EEP earnings for 2011 included proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- EEP earnings for 2011 included proceeds related to the settlement of a lawsuit during the first quarter of 2011.
- EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations of its natural gas systems.

ENBRIDGE ENERGY PARTNERS, L.P.
EEP owns and operates crude oil and liquid petroleum transportation and storage assets and natural gas and NGL gathering, treating, processing, transportation and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Canadian Mainline in the United States, the Mid-Continent Crude Oil System consisting of an interstate crude oil pipeline and storage facilities, a crude oil gathering system and interstate pipeline system in North Dakota and natural gas assets located primarily in Texas. In 2013, EEP placed into service several assets including the Texas Express NGL System, Ajax Plant and the Bakken Expansion Program. Subsidiaries of Enbridge provide services to EEP in connection with the operation of its liquids assets, including the Lakehead System.

EEP holds its natural gas and NGL midstream assets through a combination of direct and indirect holdings. As at December 31, 2013, EEP's direct interest in entities or partnerships holding the natural gas and NGL operations was approximately 61%, with the remaining ownership held by Midcoast Energy Partners, L.P. (MEP), a publicly listed partnership trading on the New York Stock Exchange. The balance of EEP's interest in the natural gas and NGL operations is held indirectly through ownership of the general partner (GP) interest, an approximate 52% limited partner interest and all incentive distribution rights of MEP. For further discussion refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – Midcoast Energy Partners, L.P. Initial Public Offering.*

Ownership Interest
Enbridge's ownership interest in EEP is impacted by EEP's issuance and sale of its Class A common units. To the extent Enbridge does not fully participate in these offerings, the Company's ownership interest in EEP is reduced. At December 31, 2013, Enbridge's ownership interest in EEP was 20.6% (2012 - 21.8%; 2011 - 23.0%). The Company's average ownership interest in EEP during 2013 was 21.1% (2012 - 23.0%; 2011 - 24.4%). Additionally, Enbridge also holds a US$1.2 billion investment in EEP preferred units. For further discussion refer to *Sponsored Investments – Enbridge Energy Partners, L.P. – EEP Preferred Unit Private Placement and Joint Funding Option Exercise*.

Distributions
EEP makes quarterly distributions of its available cash to its common unitholders. Under the Partnership Agreement, Enbridge Energy Company, Inc. (EECI), a wholly owned subsidiary of Enbridge, as GP, receives incremental incentive cash distributions, which represent incentive income on the portion of cash distributions (on a per unit basis) that exceed certain target thresholds as follows:

	Unitholders including Enbridge	GP Interest
Quarterly cash distributions per unit[1]:		
Up to $0.295 per unit	98%	2%
First target - $0.295 per unit up to $0.350 per unit	85%	15%
Second target - $0.350 per unit up to $0.495 per unit	75%	25%
Over second target - cash distributions greater than $0.495 per unit	50%	50%

1 *Distributions restated to reflect EEP's two-for-one stock split which was effective April 2011.*

In 2013, EEP paid a quarterly distribution of $0.5435 per unit to common unitholders. In 2013, Enbridge received from EEP intercompany GP incentive distributions of US$130 million (2012 - US$116 million; 2011 - US$93 million).

Results of Operations
Adjusted earnings from EEP were $165 million for the year ended December 31, 2013 compared with $141 million for the year ended December 31, 2012. The adjusted earnings increased primarily due to distributions received from Enbridge's May 2013 investment in preferred units of EEP and higher incentive distributions. Also contributing to higher adjusted earnings were contributions from EEP's liquids business due to higher tolls on EEP's major liquids pipeline assets and the positive impact of new assets placed into service. Partially offsetting the increase in adjusted earnings were lower volumes on the North Dakota system due to wide crude oil price differentials that made transportation by rail competitive,

although tightening crude oil price differentials in the second half of 2013 resulted in some volumes returning to the North Dakota system. Rail competition is expected to persist as rail provides transportation service to certain markets not currently accessible by pipelines. EEP's adjusted earnings also reflected costs related to the completion of hydrostatic testing on Line 14 of its Lakehead System, as well as higher depreciation expense associated with new assets placed into service. Also offsetting the adjusted earnings increase were lower NGL prices and volumes in EEP's natural gas and NGL businesses and higher operating and administrative expense, primarily from an increased workforce.

Adjusted earnings from EEP were $141 million for the year ended December 31, 2012 compared with $151 million for the year ended December 31, 2011. Adjusted earnings from EEP for 2012 included higher GP incentive income and strong results from the liquids business primarily due to higher average delivery volumes and increased tolls on all major liquids systems, as well as contributions from storage terminal and other facilities that were placed into service during 2012. Earnings from the natural gas business decreased as a result of lower natural gas and NGL prices. Earnings were also negatively impacted by an increase in operating and administrative costs, specifically pipeline integrity costs, personnel costs and higher property taxes.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA will again consider the status of the pipeline in light of information they acquire throughout 2014.

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

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

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

As at December 31, 2013, EEP's total cost estimate for the Line 6B crude oil release was US$1,122 million ($181 million after-tax attributable to Enbridge) which is an increase of US$302 million ($44 million after-tax attributable to Enbridge) compared to the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties other than those discussed in *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Legal and Regulatory Proceedings,* below. On March 14, 2013, EEP received an order from the 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. EEP has currently completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta. EEP is in the process of working with the EPA to ensure this work is completed as soon as reasonably possible, inclusive of obtaining the necessary state and local permitting that is required and considering weather conditions.

Of the US$302 million increase compared with December 31, 2012 related to the Line 6B crude oil release, US$280 million is primarily related to additional work required by the Order including further refinement and definition of the additional dredging scope per the Order and all associated environmental, permitting, waste removal and other related costs, as well as increased dredge activity in and around Morrow Lake and the delta area. 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 December 31, 2013 exceeded the limits of the Company's insurance coverage. The remaining increase of US$22 million reflected an estimate of the minimum amount of civil penalties EEP may be assessed under the Clean Water Act of the United States (Clean Water Act) in respect of the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Legal and Regulatory Proceedings.*

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 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

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

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, 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 December 31, 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. For the years ended December 31, 2013 and 2012, EEP recognized US$42 million ($6 million after-tax attributable to Enbridge) and US$170 million ($24 million after-tax attributable to Enbridge), respectively, of insurance recoveries as reductions to Environmental costs in the Consolidated Statements of Earnings. As at December 31, 2013, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release, out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of the remaining US$145 million coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP's claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery payment of US$42 million from the other remaining insurers and has since amended its lawsuit, such that it now includes only one insurer. 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 Lines 6A and 6B crude oil releases. 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, the Company does not expect the outcome of these actions to be material.

As at December 31, 2013, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by PHMSA that EEP paid during the third quarter of 2012. The total also included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties are ongoing.

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

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

Midcoast Energy Partners, L.P. Initial Public Offering
In May 2013, EEP formed MEP as its wholly owned subsidiary. Subsequently, on November 13, 2013, MEP completed its initial public offering (IPO) of 18.5 million Class A common units representing limited partner interests and subsequently issued an additional 2.8 million Class A common units pursuant to an underwriters' over allotment option. MEP received proceeds of approximately US$355 million.

EEP, through certain of its subsidiaries, holds a 2% GP interest and the remaining limited partner interest in MEP. Upon finalization of the offering, MEP's initial assets consisted of an approximate 39% ownership interest in EEP's natural gas and NGL midstream business. EEP retained ownership of the GP and all the incentive distribution rights in MEP. The finalization of the transaction resulted in a partial monetization of EEP's natural gas and NGL midstream assets through sale to noncontrolling interests (being MEP's public unitholders).

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

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

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 each project within one year of the final project in-service dates. For further discussion refer to *Liquidity and Capital Resources.*

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
EELP holds assets that are jointly funded by Enbridge and EEP. Included within EELP is the United States segment of Alberta Clipper, which is a 1,670-kilometre (1,000 mile) crude oil pipeline that provides service between Hardisty, Alberta and Superior, Wisconsin with capacity of 450,000 bpd. Enbridge funded 66.7% of the project's equity requirements through EELP, while 66.7% of the debt funding was made through EEP.

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

Results of Operations

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

Earnings from EELP were $38 million for the year ended December 31, 2012 compared with $42 million for the year ended December 31, 2011 due to a reduction in rates on Alberta Clipper which took effect April 1, 2012.

BUSINESS RISKS

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

Asset Utilization

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

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

EEP seeks to mitigate utilization constraints within its control. The market access and expansion projects under development are expected to reduce capacity bottlenecks and introduce new markets for customers. In conjunction with Liquids Pipelines, EEP works with the shipper community to enhance scheduling efficiency and communications as well as makes continuous improvements to models and timelines to alleviate pipeline restrictions.

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

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

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

Regulatory scrutiny over the integrity of EEP's assets, in particular its liquids assets, has the potential to increase operating costs or limit future projects. Potential regulation upgrades and changes could have an impact on the Company's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators, directly or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions.

EEP's economic regulation is driven primarily through its ownership of interstate oil pipelines and certain activities within its intrastate natural gas pipelines, which are regulated by the FERC or state regulators. The changing or rejecting of commercial arrangements by the regulators could have an adverse effect on the Company's revenues and earnings. Additionally, while EEP's gas gathering pipelines are not currently subject to FERC rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers which govern the majority of the segment's assets and the involvement of its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations; however, the risk that a regulator could overturn long-term agreements between the Company and shippers continues to exist.

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

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

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

Commodity Price Risk
EEP's gas processing business is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks have been managed by using physical and financial contracts to fix the prices of natural gas and NGL. Certain of these financial contracts do not qualify for cash flow hedge accounting therefore, EEP's earnings are exposed to associated changes in the mark-to-market value of these contracts.

ENBRIDGE INCOME FUND

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

Crude Oil Storage and Renewable Energy Transfers

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

In October 2011, the Fund also acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for an aggregate price of approximately $1.2 billion. The transaction was financed by the Fund through a combination of debt and equity, including the issuance of additional ordinary trust units of the Fund to ENF and ECT preferred units to Enbridge. ENF in turn issued additional common shares to the public and to Enbridge. Enbridge provided Bridge Financing for the balance of the purchase price. Enbridge's overall economic interest in the Fund was reduced from 72.3% to 69.2% upon completion of the transaction and associated financing.

The asset transfers described above occurred between entities under common control of Enbridge, and the intercompany gains realized by the selling entities in each of the years ended December 31, 2012 and 2011 have been eliminated from the Consolidated Financial Statements of Enbridge. Income taxes of $56 million and $98 million for the years ended December 31, 2012 and 2011, respectively, incurred on the related capital gains remain as charges to consolidated earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying entities; however, accounting recognition of such benefit is not permitted until such time as the entities are sold outside of the consolidated group.

Through these transactions, which essentially resulted in a partial monetization of these assets by Enbridge through sale to noncontrolling interests (being ENF's public shareholders), Enbridge realized a source of funds of $213 million and $210 million, as presented within Financing Activities on the Consolidated Statements of Cash Flows for the years ended December 31, 2012 and 2011, respectively. In December 2012, the Fund issued $500 million in medium-term notes. The funds from this issuance, together with its cash on hand and draws on the Fund's committed credit facility, were used to repay the $582 million Bridge Financing to Enbridge.

Saskatchewan System Shipper Complaint

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

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

Incentive and Management Fees

Enbridge receives an annual base management fee for administrative and management services it provides to the Fund, plus incentive fees. Incentive fees are paid to Enbridge based on cash distributions paid by the Fund that exceed a base distribution amount. In 2013, the Company received intercompany incentive fees of $20 million (2012 - $12 million; 2011 - $10 million) before income taxes. Enbridge also provides management services to ENF. No additional fee is charged to ENF for these services provided the Fund is paying a fee to Enbridge.

Results of Operations

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

Earnings from the Fund totalled $85 million for the year ended December 31, 2012 compared with $50 million for the year ended December 31, 2011. The increased earnings from the Fund reflected a full year of earnings from the assets acquired from a wholly-owned subsidiary of Enbridge in October 2011. Earnings also reflected the December 2012 transfer of Hardisty Storage Caverns, Hardisty Contract Terminals and the Greenwich, Amherstburg and Tilbury projects. Partially offsetting the earnings contributions were increased interest costs, higher business development expense and non-cash deferred income taxes.

BUSINESS RISKS

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines, Processing and Energy Services segment. The following risks generally relate to Green Energy and Liquids Transportation and Storage, as indicated. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Green Energy

Asset Utilization

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

Liquids Transportation and Storage

Competition

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

Economic Regulation

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

CORPORATE

EARNINGS

	2013	2012	2011
(millions of Canadian dollars)			
Noverco	**54**	27	24
Other Corporate	**(82)**	(57)	(40)
Adjusted loss	**(28)**	(30)	(16)
Noverco - changes in unrealized derivative fair value gains/(loss)	**4**	(10)	-
Noverco - equity earnings adjustment	**-**	(12)	-
Other Corporate - changes in unrealized derivative fair value loss	**(306)**	(22)	(87)
Other Corporate - impact of tax rate changes	**18**	(11)	6
Other Corporate - foreign tax recovery	**4**	29	-
Other Corporate - asset impairment loss	**(6)**	-	-
Other Corporate - unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**-**	(17)	24
Other Corporate - tax on intercompany gain on sale	**-**	(56)	(98)
Loss attributable to common shareholders	**(314)**	(129)	(171)

Total adjusted loss from Corporate was $28 million for the year ended December 31, 2013 compared with adjusted losses of $30 million for the year ended December 31, 2012 and $16 million for the year ended December 31, 2011. The increase in adjusted loss reflected higher dividends paid on additional preference shares issued to fund the Company's growth projects. Partially offsetting the increased loss were higher contributions from Noverco's underlying assets.

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

- Noverco earnings for 2013 and 2012 included changes in the unrealized fair value gains or losses on derivative financial instruments.
- Noverco earnings for 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Other Corporate loss for each period included changes in the unrealized fair value loss on derivative financial instruments related to forward foreign exchange risk management positions.
- Other Corporate loss for each period reflected the anticipated future impact of tax rate changes.
- Other Corporate loss for 2013 and 2012 were reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate loss for 2013 included charges related to asset impairment losses.
- Other Corporate loss for 2012 and 2011 included net unrealized foreign exchange gain/(loss) on the translation of foreign-denominated intercompany balances.
- Other Corporate loss for 2012 and 2011 were impacted by tax on an intercompany gain on sale. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers* for details of the transactions.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. Noverco is a holding company that owns approximately 71% of Gaz Metro Limited Partnership (Gaz Metro), a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the state of Vermont. Noverco also holds, directly and indirectly, an investment in Enbridge common shares. In both 2013 and 2012, the Board of Directors of Noverco authorized the sale of a portion of its Enbridge common share holding to rebalance Noverco's asset mix. On May 28, 2013, Noverco sold 15 million Enbridge common shares through a secondary offering. Enbridge's share of the net after-tax proceeds of approximately $248 million was received as dividends from Noverco on June 4, 2013 and was used to pay a portion of the Company's quarterly dividend on September 1, 2013. A portion of this dividend did not qualify for the enhanced dividend tax credit in Canada and, accordingly, was not designated as an "eligible dividend". The dividend was a "qualified dividend" for United States tax purposes.

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

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

Results of Operations

Noverco adjusted earnings increased to $54 million for the year ended December 31, 2013 from $27 million for the year ended December 31, 2012. Noverco adjusted earnings included returns on the Company's preferred share investment as well as its equity earnings from Noverco's underlying gas and power distribution investments. The increase in adjusted earnings was primarily attributable to higher volumes within Gaz Metro's Quebec-based gas distribution franchise area, contributions from a full year of operations of power distribution assets acquired in mid-2012 and a small one-time gain on sale of assets of approximately $3 million. Adjusted earnings also increased slightly due to higher preferred share investment earnings. Partially offsetting the adjusted earnings increase was a lower ROE allowed by the regulator for Gaz Metro.

Noverco's investment in power distribution operations is subject to seasonality, similar to gas distribution operations, with the majority of its annual earnings achieved during the colder months of the first quarter. This seasonal pattern heightens the effect of the earnings increase attributable to the power distribution acquisition since the 2013 results included the first quarter, whereas 2012 did not given that the acquisition took place mid-year.

Noverco adjusted earnings were $27 million for the year ended December 31, 2012 compared with $24 million for the year ended December 31, 2011 and reflected contributions from the Company's increased preferred share investment and Noverco's underlying gas distribution investments.

OTHER CORPORATE

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

Preference Share Issuances
Since July 2011, the Company has issued 204 million preference shares for gross proceeds of approximately $5,127 million with the following characteristics. See *Outstanding Share Data*.

	Gross Proceeds	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)						
Series B[5]	$500 million	4.0%	$1.00	$25	June 1, 2017	Series C
Series D[5]	$450 million	4.0%	$1.00	$25	March 1, 2018	Series E
Series F[5]	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H[5]	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J[5]	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L[5]	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N[5]	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O
Series P[5]	$400 million	4.0%	$1.00	$25	March 1, 2019	Series Q
Series R[5]	$400 million	4.0%	$1.00	$25	June 1, 2019	Series S
Series 1[5]	US$400 million	4.0%	US$1.00	US$25	June 1, 2018	Series 2
Series 3[5]	$600 million	4.0%	$1.00	$25	September 1, 2019	Series 4
Series 5[5]	US$200 million	4.4%	US$1.10	US$25	March 1, 2019	Series 6
Series 7[5]	$250 million	4.4%	$1.10	$25	March 1, 2019	Series 8

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*
2 *The Company may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*
3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.*
4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4) or 2.6% (Series 8)); or US$25 x (number of days in quarter/365) x (three month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).*
5 *For dividends declared, see* Liquidity and Capital Resources – Financing Activities.

Common Share Issuance
On 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.

Results of Operations
Other Corporate adjusted loss was $82 million for the year ended December 31, 2013 compared with an adjusted loss of $57 million for the year ended December 31, 2012. The increased loss was attributable to dividends paid on additional preference shares issued to fund the Company's slate of growth projects. Partially offsetting increased preference share dividends were lower net Corporate segment finance costs and lower operating and administrative costs.

Other Corporate adjusted loss was $57 million for the year ended December 31, 2012 compared with an adjusted loss of $40 million for the year ended December 31, 2011 and also reflected higher dividends paid on incremental preference shares issued.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the level of growth projects secured or under development. Access to timely funding from capital markets could be limited by factors outside its control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, the Company actively manages financing plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. The Company targets to maintain sufficient standby liquidity to bridge fund through protracted capital markets disruptions of up to one year.

In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company's financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and it identifies potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles, with the objective of diversifying funding sources and maintaining access to low cost capital.

The Company's financing strategy includes optimizing the funding of its enterprise-wide slate of growth projects, including through its sponsored vehicles. During 2013, several actions were taken 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 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 the Lakehead System Mainline Expansion projects by 15% to 25%. EEP retains the option to increase its economic interest back up to 40% in each of these projects within one year of their respective 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, and again on December 2, 2013.
- On November 13, 2013, MEP, a subsidiary of EEP, completed its IPO of 18.5 million Class A common units representing limited partner interests and subsequently issued an additional 2.8 million Class A common units pursuant to the exercise of an underwriters' option. MEP received proceeds of approximately US$355 million from the offering. Upon finalization of the offering, MEP's initial assets consisted of an approximate 39% ownership interest in EEP's natural gas and NGL midstream business. EEP, through certain of its subsidiaries, holds a 2% GP interest and the remaining limited partner interest in MEP. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Midcoast Energy Partners, L.P. Initial Public Offering*.

In accordance with its financing plan, the Company has been active in the capital markets with the following issuances during 2013:

- Corporate - $1,467 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;
- EGD - $400 million medium-term notes;
- EEM - US$509 million in listed shares;
- MEP - US$355 million in common units; and
- The Fund - $96 million in common units.

In addition to these debt and equity issuances, 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 significantly bolstered its committed bank credit facilities in 2013, including securement of a US$850 million facility by MEP. 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 December 31, 2013 and 2012.

		December 31, 2013			December 31, 2012
	Maturity Dates[2]	Total Facilities	Draws[3]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**266**	**34**	300
Gas Distribution	2014-2019	**713**	**382**	**331**	712
Sponsored Investments	2015-2018	**4,781**	**809**	**3,972**	3,162
Corporate	2015-2018	**11,805**	**3,651**	**8,154**	9,108
		17,599	**5,108**	**12,491**	13,282
Southern Lights project financing[1]	2014-2015	**1,570**	**1,498**	**72**	1,484
Total credit facilities		**19,169**	**6,606**	**12,563**	14,766

1 Total facilities inclusive of $63 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.

Excluding project financing, the Company's net available liquidity of $12,909 million at December 31, 2013 was inclusive of $756 million of unrestricted cash and cash equivalents and net of bank indebtedness of $338 million.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2013, the Company was in compliance with all debt covenants and expects to continue to comply with such covenants.

Strong growth in internal cashflow, ready access to liquidity from diversified sources and a stable business model have enabled Enbridge to obtain and maintain a strong credit profile. The Company actively monitors and manages key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital under attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cashflow and the ratio of debt to total capital. As at December 31, 2013, the Company's debt capitalization ratio was 58.2% compared with 60.2% as at December 31, 2012.

The Company invests a portion of its surplus cash in short-term investment grade instruments with creditworthy counterparties. Short-term investments were $85 million as at December 31, 2013 compared with $950 million as at December 31, 2012. Surplus cash at December 31, 2013 arose primarily due to pre-funding of equity requirements and will be used to fund the Company's growth projects.

There are no material restrictions on the Company's cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $27 million for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

Excluding current maturities of long-term debt, the Company had a negative working capital position of $967 million at December 31, 2013 compared with a positive working capital position of $183 million at December 31, 2012. The decrease in working capital is mainly attributable to a reduction in cash on hand combined with an increase in construction payables, both of which temporarily fund growth capital expenditures. Partially offsetting these decreases was an increase in accounts receivable in respect of the Company's operations that have grown period-over-period.

Despite the negative working capital as at December 31, 2013, the Company has significant net available liquidity through committed credit facilities and other sources as previously discussed, which allow the funding of liabilities as they become due. As at December 31, 2013, the net available liquidity totalled $12,909 million. In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

December 31,	**2013**	2012
(millions of Canadian dollars)		
Cash and cash equivalents[1]	**790**	1,795
Accounts receivable and other[2]	**5,021**	4,026
Inventory	**1,115**	779
Assets held for sale[3]	**17**	-
Bank indebtedness	**(338)**	(479)
Short-term borrowings	**(374)**	(583)
Accounts payable and other[4]	**(6,710)**	(5,052)
Interest payable	**(228)**	(196)
Environmental liabilities	**(260)**	(107)
Working capital	**(967)**	183

1 *Includes short-term investments and restricted cash of amounts in trust.*
2 *Includes Accounts receivable from affiliates.*
3 *Net of current liabilities held for sale.*
4 *Includes Accounts payable to affiliates.*

OPERATING ACTIVITIES

Cash provided by operating activities for the year ended December 31, 2013 was $3,341 million compared with $2,874 million and $3,371 million for the years ended December 31, 2012 and 2011, respectively. Excluding the timing effect of changes in operating assets and liabilities, the Company has delivered a growing cash flow stream over the last two years.

The cash flow increase was attributable in part to the successful completion of significant projects in recent years. As discussed in *Performance Overview*, new Liquids Pipelines assets placed into service in 2012 and 2013, completion of Bakken Expansion in 2013 and addition of five wind farms and two solar farms between 2011 and 2013 all contributed to the increase in period-over-period operating cash flows. In addition to the new assets, the Company's core businesses also achieved higher operating cash flows in 2013, mainly attributable to higher throughput in Liquids Pipelines, favourable market conditions in Energy Services and stronger contributions from EEP and the Fund. Partially offsetting the positive factors for 2013 were higher financing costs as the Company significantly advanced its funding plan in 2013, as well as lower dividend paid by Noverco in 2013 compared with 2012. In 2013, Noverco paid Enbridge a one-time dividend of $248 million compared with $317 million paid in 2012 upon realization of a substantial gain on the disposition of a portion of its investment in Enbridge shares.

The Company's operating assets and liabilities fluctuate due to variations in commodity prices and sales volumes within Energy Services, the timing of tax payments, the payment of power deposits to support the Company's growth projects, as well as general variations in activity levels within the Company's businesses. The year-over-year increase in cash provided by operating activities in 2013 was impacted by a favourable variance of $251 million for changes in operating assets and liabilities, mainly attributable to higher activity in the Company's marketing and gas distribution businesses, which had higher accounts payable balance resulting from higher purchases, partially offset by increases in accounts receivable and inventory balances.

Cash provided by operating activities for 2012 was lower compared to 2011 primarily due to an unfavourable variance of $1,061 million in the changes in operating assets and liabilities. In addition, cash from operating activities during the fourth quarter of 2012 included an outflow of US$202 million related to a voluntary pre-payment of certain derivative liabilities. The payment was transacted to optimize cash management opportunities and did not alter the risk management properties of the derivative position. These cash outflows were partially offset by the favourable operating performance of the Canadian Mainline under CTS, strong volumes across all of the Company's liquids pipelines assets and general cash growth from development projects placed in service in recent years. The dividend received from Noverco in 2012, as discussed above, also impacted the period-over-period cash flows for 2012.

INVESTING ACTIVITIES

Cash used in investing activities was $9,431 million for the year ended December 31, 2013 compared with $6,204 million for the year ended December 31, 2012 and $5,079 million for the year ended December 31, 2011. Cash used in investing activities has increased on a year-over-year basis primarily due to additions to property, plant and equipment associated with construction of the Company's expansion initiatives, which are described in *Growth Projects – Commercially Secured Projects*. A summary of additions to property, plant and equipment for the years ended December 31, 2013, 2012 and 2011 is as follows:

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Liquids Pipelines	**4,359**	1,926	906
Gas Distribution	**533**	445	478
Gas Pipelines, Processing and Energy Services	**744**	933	959
Sponsored Investments	**2,565**	1,886	1,157
Corporate	**34**	4	27
Total capital expenditures	**8,235**	5,194	3,527

Other notable investing activities in 2013 and 2012 included the funding of various investment and joint ventures, primarily the Texas Express NGL System and Seaway Pipeline. The Company's investing activities for the year ended December 31, 2012 also included the acquisition of Silver State and Pipestone and Sexsmith, as well as the remaining 10% interest in Greenwich. In comparison, for the year ended December 31, 2011, the Company acquired its original 50% interest in Seaway Pipeline and increased its Noverco preferred shares investment.

FINANCING ACTIVITIES

Cash generated from financing activities was $5,070 million for the year ended December 31, 2013 compared with $4,395 million for the year ended December 31, 2012 and $2,030 million for the year ended December 31, 2011. The cash inflow from financing activities has increased over the 2011 to 2013 time frame as the Company executed its funding and liquidity plan in support of its long-term growth plan. During 2013, the Company raised a total of $4,901 million through capital markets transactions, including $1,428 million in preference shares, $628 million in common shares and $2,845 million of medium-term notes. The Company also bolstered its liquidity in 2013 through the securement of additional credit facilities and increased draws on such facilities and commercial paper by $1,562 million in the year. The additional preference and common shares outstanding during the year together with an 11% increase in the common share dividend rate, gave rise to an increase in dividends paid in 2013 compared with the prior year.

Financing activities also included transactions between the Company's Sponsored Investments and their public unit holders, also referred to as noncontrolling interests. Significant transactions during the year included the IPO by MEP which raised proceeds of US$355 million. EEM and the Fund also completed issuances of units to the public of US$509 million and $96 million, respectively, in support of the growth initiatives underway by each of those entities. The Company's sponsored vehicles also pay quarterly distributions to their public unit holders in accordance with distribution policies approved by their respective Boards.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the year ended December 31, 2013, dividends declared were $1,035 million (2012 - $895 million), of which $674 million (2012 - $597 million) were paid in cash and reflected in financing activities. The remaining $361 million (2012 - $297 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the years ended December 31, 2013 and 2012, 34.9% and 33.2%, respectively, of total dividends declared were reinvested.

On December 4, 2013, the Enbridge Board of Directors declared the following quarterly dividends with the exception of Preference Shares, Series 7, which was declared on January 15, 2014. All dividends are payable on March 1, 2014 to shareholders of record on February 14, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7[1]	$0.23810

1 A cash dividend of $0.2381 per share will be payable on March 1, 2014 to Series 7 preference shareholders. The regular quarterly dividend of $0.275 per share will begin in the second quarter of 2014.

CONTRACTUAL OBLIGATIONS

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

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	25,532	3,184	2,324	1,911	18,113
Capital and operating leases	828	116	219	150	343
Long-term contracts	13,347	6,042	2,448	1,742	3,115
Pension obligations[2]	152	152	-	-	-
Total contractual obligations	39,859	9,494	4,991	3,803	21,571

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

2 Assumes only required payments will be made into the pension plans in 2014. Contributions are made in accordance with independent actuarial valuations as at December 31, 2013. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $4,455 million which are expected to be paid over the next five years.

CONTINGENCIES

United States Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Lines 6A and 6B crude oil releases. 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. 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.

EEP's estimated cost at December 31, 2013 for the Line 6B crude oil release included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties are ongoing.

One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court. The parties are currently operating under an agreed interim order. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases.*

As at December 31, 2013, the Company was not aware of any claims related to the Line 14 crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Line 14 Crude Oil Release*.

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 LEGAL AND REGULATORY PROCEEDINGS

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

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Series A[2]	5,000,000
Preference Shares, Series B[2,3]	20,000,000
Preference Shares, Series D[2,4]	18,000,000
Preference Shares, Series F[2,5]	20,000,000
Preference Shares, Series H[2,6]	14,000,000
Preference Shares, Series J[2,7]	8,000,000
Preference Shares, Series L[2,8]	16,000,000
Preference Shares, Series N[2,9]	18,000,000
Preference Shares, Series P[2,10]	16,000,000
Preference Shares, Series R[2,11]	16,000,000
Preference Shares, Series 1[2,12]	16,000,000
Preference Shares, Series 3[2,13]	24,000,000
Preference Shares, Series 5[2,14]	8,000,000
Preference Shares, Series 7[2,15]	10,000,000
Common Shares - issued and outstanding (voting equity shares)	831,509,051
Stock Options - issued and outstanding (15,524,712 vested)	33,516,016

1 *Outstanding share data information is provided as at February 7, 2014.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

QUARTERLY FINANCIAL INFORMATION[1]

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

2012[1]	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	6,532	5,445	5,676	7,007	24,660
Earnings attributable to common shareholders	261	8	187	146	602
Earnings per common share	0.34	0.01	0.24	0.19	0.78
Diluted earnings per common share	0.34	0.01	0.24	0.18	0.77
Dividends per common share	0.2825	0.2825	0.2825	0.2825	1.13
EGD - warmer/(colder) than normal weather	24	-	-	(1)	23
Changes in unrealized derivative fair value and intercompany foreign exchange loss	110	252	93	81	536

1 *Revenues, Earnings attributable to common shareholders, Earnings per common share and Diluted earnings per common share for the 2012 comparative periods have been revised. See Note 4 to the December 31, 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.

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.

Included in earnings are after-tax costs of $40 million, $13 million and $3 million incurred respectively in the second, third and fourth quarters of 2013, in connection with the Line 37 crude oil release.

Reflected in earnings is the Company's share of leak remediation costs associated with the Line 6B and Line 14 crude oil releases. Remediation costs of $24 million, $6 million, $5 million and $9 million were recognized in the first, second, third and fourth quarter of 2013; $2 million and $7 million in the second and third quarter of 2012, respectively. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013 and $24 million in the third quarter of 2012, respectively.

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. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. Also included in the fourth quarter of 2012 was a $63 million after-tax gain on recognition of a regulatory asset related to OPEB within EGD. Fourth quarter earnings for 2012 were also impacted by the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million 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 construction commencement and in-service dates, are described in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development.*

RELATED PARTY TRANSACTIONS

All related party transactions are undertaken in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $6 million for the year ended December 31, 2013 (2012 - $6 million; 2011 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services have transportation commitments with several joint venture affiliates that are accounted for using the equity method. Total amounts charged for transportation services for the year ended December 31, 2013 were $222 million (2012 - $127 million; 2011 - $106 million).

Additionally, certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services made natural gas purchases of $99 million (2012 - $15 million; 2011 - nil) and sales of $10 million (2012 - $7 million; 2011 - $5 million) with several joint venture affiliates during the year ended December 31, 2013.

Amounts receivable from affiliates include a series of loans to Vector totalling $181 million (2012 - $178 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates from 3% to 8%.

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 whereby it economically hedges a minimum level of foreign currency denominated earnings exposures identified over a five-year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales, 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 2017 through execution of floating to fixed interest rate swaps with an average swap rate of 1.5%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018. A total of $10,419 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.8%.

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 interests in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

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

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of derivative instruments on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**56**	(12)	(22)
Interest rate contracts	**814**	(46)	(724)
Commodity contracts	**(9)**	52	72
Other contracts	**(2)**	(3)	6
Net investment hedges			
Foreign exchange contracts	**(81)**	1	(26)
	778	(8)	(694)
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*			
Foreign exchange contracts[1]	**(8)**	1	1
Interest rate contracts[2]	**107**	(1)	(10)
Commodity contracts[3]	**1**	(3)	(55)
Other contracts[4]	**-**	2	(2)
	100	(1)	(66)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**51**	23	11
Commodity contracts[3]	**(3)**	(3)	5
	48	20	16
Amount of gains/(loss) from non-qualifying derivatives included in earnings			
Foreign exchange contracts[1]	**(738)**	120	(179)
Interest rate contracts[2]	**(10)**	(2)	9
Commodity contracts[3]	**(496)**	(765)	280
Other contracts[4]	**(3)**	(2)	4
	(1,247)	(649)	114

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

LIQUIDITY RISK
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 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 individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with 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.

GENERAL BUSINESS RISKS

Strategic and Commercial Risks

Public Opinion

Public opinion or reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by media attention directed to development projects such as Northern Gateway. Potential impacts of a negative public opinion may include loss of business, legal action, increased regulatory oversight and costs.

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

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;

- having strong corporate governance practices, including a Statement on Business Conduct, which requires all employees to certify their compliance with Company policy on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's CSR Policy, Climate Change Policy, Aboriginal and Native American Policy and the Neutral Footprint Initiative).

Project Execution

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

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

The Company strives to be an industry leader in project execution through Major Projects. Major Projects is centralized and has a clearly defined governance structure and process for all major projects, with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Early stage project risks are mitigated by early assessment of stakeholder issues to develop proactive relationships and specific action plans. Consultations with regulators are held in-advance of project construction to enhance understanding of project rationale and ensure applications are compliant and robust, while at all times maintaining a strong focus on integrity and public safety. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors and those selected are chosen based on the Company's strict adherence to safety including robust safety standards embedded in contracts with suppliers. The Company has assessed work volumes across the next several years across its major projects to optimize the expected costs, supply of services, material and labour to execute the projects. Underpinning this approach is Major Project's Project Lifecycle Gating Control tool which helps to ensure schedule, cost, safety and quality objectives are on track and met for each stage of a project's development and construction.

Planning and Investment Analysis

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

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

Human Resources

Like many other companies in the energy sector, Enbridge faces a risk that it will be unable to attract and retain the necessary skilled people resources to fulfill its growth plan. In response to the needs of commercially secured growth projects, the Company expects to require approximately 1,000 new positions over the next three years. Factors which could impact Enbridge's ability to secure these resources include labour shortages, particularly within the Alberta market and the shortage of technically skilled workers; rates of retirement and turnover and the ability to successfully transfer knowledge; and retaining Enbridge's reputation as a great employer.

Operational and Economic Regulation

Many of the Company's operations are regulated and are subject to both operational and economic regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. Operational regulation risk relates to the failure to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators, directly or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. As stated previously, while the Company believes the safe and reliable operation of its assets is the best manner to adhere to existing regulations, the potential remains for regulators to make unilateral decisions that could have a non-recoverable financial impact on the Company.

Economic regulation risk relates to the risk regulators or other government entities change or reject proposed or existing commercial arrangements. These changes may adversely affect toll structures, other aspects of pipeline operations or the operations of shippers. Recently, shippers have challenged toll increases on various pipelines owned by Enbridge and some of Enbridge's competitors. Enbridge retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize economic and regulation risk.

Operational Risks

Environmental Incident

An environmental incident could have lasting reputational impacts to Enbridge and could impact its ability to work with various stakeholders. In addition to the cost of remediation activities (to the extent not covered by insurance) environmental incidents may lead to an increased cost of operation and insuring the Company's assets, thereby negatively impacting earnings. The Company mitigates risk of environmental incident through its ORM Plan, which broadly aims to position Enbridge as the industry leader for system integrity, environmental and safety programs. Through the ORM Plan, the Company has expanded its maintenance, excavation and repair programs which are supported by operating and capital budgets directed to pipeline integrity. Emergency response plans, operator training and landowner education programs are included in the Company's response preparedness. In addition, the role of Senior Vice President, Enterprise Safety & Operational Reliability was established in 2013. The new centralized role is accountable for defining and executing on an enterprise-wide vision, culture and set of integrated strategies and policies that support Enbridge's objective of being the industry leader in process, public and personal safety, operational reliability and environmental protection.

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

Public, Worker and Contractor Safety

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

Safety and operational reliability are the most important priorities at Enbridge. Enbridge's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its ORM Plan and emergency response preparedness, as described above. Enbridge believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents.

Service Interruption Incident

A service interruption due to a major power disruption or curtailment on commodity supply could have a significant impact on the Company's ability to operate its assets and negatively impact future earnings, relationships with stakeholders and the Company's reputation. Specifically, for Gas Distribution, any prolonged interruptions would ultimately impact gas distribution customers. Service interruptions that impact the Company's crude oil transportation services can negatively impact shippers' operations and earnings as they are dependent on Enbridge services to move their product to market or fulfill their own contractual arrangements. The Company mitigates service interruption risk through its diversified sources of supply, storage withdrawal flexibility, backup power systems, critical parts inventory and redundancies for critical equipment.

Information Systems Incident

The Company's infrastructure, applications and data are becoming more integrated, creating an increased risk that failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems. As part of the Company's ORM Plan, the Company has continued to broaden the scope of its systems security with increased mitigation activities focused on the prevention, detection and necessary response to any potential systems security incident. Additionally, to increase accountability in relation to systems security, all information technology security operations in the Company are consolidated under one leadership structure to increase consistency and compliance with the Company's security requirements.

Business Environment Risks

Aboriginal Relations

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

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

Special Interest Groups including Non-Governmental Organizations

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

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

CRITICAL ACCOUNTING ESTIMATES

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2013 of $42,279 million (2012 - $33,318 million), or 73.4% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

ASSET IMPAIRMENT

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

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Alberta Energy Regulator and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. As at December 31, 2013, the Company's significant regulatory assets totalled $1,138 million (2012 - $1,109 million) and significant regulatory liabilities totalled $1,016 million (2012 - $941 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and OPEB to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the universal method. This method involves complex actuarial calculations using several assumptions including discount rates, which were determined by referring to high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The actual return on plan assets exceeded the expected return on plan assets by $101 million for the year ended December 31, 2013 (2012 - $24 million) as disclosed in Note 25, Retirement and Postretirement Benefits, to the 2013 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2013 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	149	22	18	2
Decrease in expected return on assets	-	8	-	-
Decrease in rate of salary increase	(30)	(10)	-	-

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments are detailed in Note 29, Commitments and Contingencies, of the 2013 Annual Consolidated Financial Statements. In addition, any unasserted claims that later may become evident could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS

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. and Enbridge Pipelines (Westspur) Inc. (Group 2 companies). In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies and issued its decision on February 14, 2013. The outcome does not materially impact tolls. On February 28, 2013, Group 1 companies filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the 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 commenced January 14, 2014 with the decision expected in the second quarter of 2014.

Currently, for the majority of the Company's assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the 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 Securities and Exchange Commission (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.

Presentation of Unrecognized Tax Benefits
Effective December 31, 2013, the Company elected to early adopt ASU 2013-11, which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

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.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As at December 31, 2013, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

Management's Report on Internal Control over Financial Reporting

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

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

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

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2013, based on the framework established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2013.

During the year ended December 31, 2013, there has been no material change in the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as at December 31, 2013 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

NON-GAAP RECONCILIATIONS

(millions of Canadian dollars)	**2013**	2012	2011
Earnings attributable to common shareholders	**446**	602	801
Adjusting items:			
Liquids Pipelines			
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**268**	(42)	48
Canadian Mainline - Line 9 tolling adjustment	**-**	(6)	(10)
Canadian Mainline - shipper dispute settlement	**-**	-	(14)
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**56**	-	-
Regional Oil Sands System - make-up-rights adjustment	**13**	-	-
Regional Oil Sands System - make-up-rights out-of-period adjustment	**37**	-	-
Regional Oil Sands System - long-term contractual recovery out-of-period adjustment, net	**(31)**	-	-
Regional Oil Sands System - prior period adjustment	**-**	6	-
Regional Oil Sands System - asset impairment write-off	**-**	-	8
Spearhead Pipeline - changes in unrealized derivative fair value gains[1]	**-**	-	(1)
Gas Distribution			
EGD - gas transportation costs out-of-period adjustment	**56**	-	-
EGD - warmer/(colder) than normal weather	**(9)**	23	(1)
EGD - tax rate changes	**-**	9	-
EGD - recognition of regulatory asset	**-**	(63)	-
Other Gas Distribution and Storage - regulatory deferral write-off	**-**	-	262
Gas Pipelines, Processing and Energy Services			
Aux Sable - changes in unrealized derivative fair value (gains)/loss[1]	**-**	(10)	7
Energy Services - changes in unrealized derivative fair value (gains)/loss[1]	**206**	537	(125)
Offshore - asset impairment loss	**-**	105	-
Other - changes in unrealized derivative fair value (gains)/loss[1]	**61**	-	(24)
Sponsored Investments			
EEP - leak insurance recoveries	**(6)**	(24)	(50)
EEP - leak remediation costs	**44**	9	33
EEP - changes in unrealized derivative fair value (gains)/loss[1]	**6**	2	(3)
EEP - tax rate differences/changes	**3**	-	-
EEP - gain on sale of non-core assets	**(2)**	-	-
EEP - NGL trucking and marketing investigation costs	**-**	1	3
EEP - prior period adjustment	**-**	(7)	-
EEP - shipper dispute settlement	**-**	-	(8)
EEP - lawsuit settlement	**-**	-	(1)
EEP - impact of unusual weather conditions	**-**	-	1
Corporate			
Noverco - changes in unrealized derivative fair value (gains)/loss[1]	**(4)**	10	-
Noverco - equity earnings adjustment	**-**	12	-
Other Corporate - changes in unrealized derivative fair value loss[1]	**306**	22	87
Other Corporate - impact of tax rate changes	**(18)**	11	(6)
Other Corporate - foreign tax recovery	**(4)**	(29)	-
Other Corporate - asset impairment loss	**6**	-	-
Other Corporate - unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**-**	17	(24)
Other Corporate - tax on intercompany gain on sale	**-**	56	98
Adjusted earnings	**1,434**	1,241	1,081

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.

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2013

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2013, based on the framework established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2013.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).

"signed"

Al Monaco
President & Chief Executive Officer

"signed"

J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 14, 2014

Independent Auditor's Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2013 and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2013 and an audit of its 2011 consolidated financial statements. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2013 and December 31, 2012 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2013, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2013 and December 31, 2012 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

Report on internal control over financial reporting

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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

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

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

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

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

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

Opinion
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 14, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**26,039**	18,494	20,374
Gas distribution sales	**2,265**	1,910	1,906
Transportation and other services	**4,614**	4,256	4,509
	32,918	24,660	26,789
Expenses			
Commodity costs	**25,222**	17,959	19,627
Gas distribution costs	**1,585**	1,220	1,281
Operating and administrative	**3,014**	2,739	2,259
Depreciation and amortization	**1,370**	1,236	1,147
Environmental costs, net of recoveries *(Note 29)*	**362**	(88)	(116)
	31,553	23,066	24,198
	1,365	1,594	2,591
Income from equity investments *(Note 12)*	**330**	195	233
Other income/(expense) *(Note 26)*	**(135)**	238	116
Interest expense *(Note 17)*	**(947)**	(841)	(928)
	613	1,186	2,012
Income taxes *(Note 24)*	**(123)**	(171)	(523)
Earnings from continuing operations	**490**	1,015	1,489
Discontinued operations *(Note 10)*			
Earnings/(loss) from discontinued operations before income taxes	**6**	(123)	(9)
Income taxes (expense)/recovery from discontinued operations	**(2)**	44	3
Earnings/(loss) from discontinued operations	**4**	(79)	(6)
Earnings before extraordinary loss	**494**	936	1,483
Extraordinary loss, net of tax *(Note 6)*	**-**	-	(262)
Earnings	**494**	936	1,221
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**135**	(229)	(407)
Earnings attributable to Enbridge Inc.	**629**	707	814
Preference share dividends	**(183)**	(105)	(13)
Earnings attributable to Enbridge Inc. common shareholders	**446**	602	801
Earnings attributable to Enbridge Inc. common shareholders			
Earnings from continuing operations	**442**	681	1,069
Earnings/(loss) from discontinued operations, net of tax	**4**	(79)	(6)
Extraordinary loss, net of tax *(Note 6)*	**-**	-	(262)
	446	602	801
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**0.55**	0.88	1.43
Discontinued operations	**-**	(0.10)	(0.01)
Extraordinary item	**-**	-	(0.35)
	0.55	0.78	1.07
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**0.55**	0.87	1.40
Discontinued operations	**-**	(0.10)	(0.01)
Extraordinary item	**-**	-	(0.34)
	0.55	0.77	1.05

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings	**494**	936	1,221
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**697**	(176)	(582)
Change in unrealized gains/(loss) on net investment hedges	**(96)**	13	(19)
Other comprehensive income/(loss) from equity investees	**11**	2	(17)
Reclassification to earnings of realized cash flow hedges	**72**	7	14
Reclassification to earnings of unrealized cash flow hedges	**39**	20	12
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	**27**	18	21
Actuarial gains/(loss) on pension plans and other postretirement benefits	**114**	(56)	(165)
Change in foreign currency translation adjustment	**710**	(158)	144
Other comprehensive income/(loss)	**1,574**	(330)	(592)
Comprehensive income	**2,068**	606	629
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(276)**	(165)	(327)
Comprehensive income attributable to Enbridge Inc.	**1,792**	441	302
Preference share dividends	**(183)**	(105)	(13)
Comprehensive income attributable to Enbridge Inc. common shareholders	**1,609**	336	289

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**3,707**	1,056	125
Preference shares issued	**1,434**	2,651	931
Balance at end of year	**5,141**	3,707	1,056
Common shares *(Note 20)*			
Balance at beginning of year	**4,732**	3,969	3,683
Common shares issued	**582**	388	-
Dividend reinvestment and share purchase plan	**361**	297	229
Shares issued on exercise of stock options	**69**	78	57
Balance at end of year	**5,744**	4,732	3,969
Additional paid-in capital			
Balance at beginning of year	**522**	242	131
Stock-based compensation	**28**	26	18
Options exercised	**(17)**	(17)	(7)
Issuance of treasury stock *(Note 12)*	**208**	236	-
Dilution gains and other	**5**	35	100
Balance at end of year	**746**	522	242
Retained earnings			
Balance at beginning of year	**3,173**	3,643	3,729
Earnings attributable to Enbridge Inc.	**629**	707	814
Preference share dividends	**(183)**	(105)	(13)
Common share dividends declared	**(1,035)**	(895)	(759)
Dividends paid to reciprocal shareholder	**19**	20	25
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 19)*	**(53)**	(197)	(153)
Balance at end of year	**2,550**	3,173	3,643
Accumulated other comprehensive loss *(Note 22)*			
Balance at beginning of year	**(1,762)**	(1,496)	(984)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**1,163**	(266)	(512)
Balance at end of year	**(599)**	(1,762)	(1,496)
Reciprocal shareholding *(Note 12)*			
Balance at beginning of year	**(126)**	(187)	(154)
Issuance of treasury stock	**40**	61	-
Acquisition of equity investment	**-**	-	(33)
Balance at end of year	**(86)**	(126)	(187)
Total Enbridge Inc. shareholders' equity	**13,496**	10,246	7,227
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**3,258**	3,141	2,424
Earnings/(loss) attributable to noncontrolling interests	**(111)**	241	416
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**166**	(39)	(84)
Change in foreign currency translation adjustment	**223**	(60)	66
Reclassification to earnings of realized cash flow hedges	**4**	23	(63)
Reclassification to earnings of unrealized cash flow hedges	**14**	13	4
	407	(63)	(77)
Comprehensive income attributable to noncontrolling interests	**296**	178	339
Distributions	**(468)**	(421)	(355)
Contributions	**922**	382	735
Dilution gains	**-**	6	22
Acquisitions *(Note 7)*	**-**	(25)	(27)
Other	**6**	(3)	3
Balance at end of year	**4,014**	3,258	3,141
Total equity	**17,510**	13,504	10,368
Dividends paid per common share	**1.26**	1.13	0.98

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Operating activities			
Earnings	**494**	936	1,221
(Earnings)/loss from discontinued operations	**(4)**	79	6
Depreciation and amortization	**1,370**	1,236	1,147
Deferred income taxes *(Note 24)*	**131**	3	365
Changes in unrealized (gains)/loss on derivative instruments, net	**1,262**	665	(73)
Cash distributions in excess of equity earnings	**355**	439	102
Regulatory asset write-off *(Note 6)*	**-**	-	262
Impairment	**6**	39	11
Other	**(9)**	109	11
Changes in regulatory assets and liabilities	**(11)**	44	38
Changes in environmental liabilities, net of recoveries *(Note 29)*	**148**	(26)	(118)
Changes in operating assets and liabilities *(Note 27)*	**(409)**	(660)	401
Cash provided by continuing operations	**3,333**	2,864	3,373
Cash provided by/(used in) discontinued operations *(Note 10)*	**8**	10	(2)
	3,341	2,874	3,371
Investing activities			
Additions to property, plant and equipment	**(8,235)**	(5,194)	(3,527)
Long-term investments	**(1,018)**	(531)	(1,515)
Additions to intangible assets	**(212)**	(163)	(154)
Acquisitions, net of cash acquired *(Note 7)*	**-**	(340)	(33)
Affiliate loans, net	**8**	8	7
Proceeds on sale of investments and net assets	**41**	18	-
Government grant	**-**	-	145
Changes in restricted cash	**(15)**	(2)	(2)
	(9,431)	(6,204)	(5,079)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**(350)**	412	224
Net change in commercial paper and credit facility draws	**1,562**	(294)	(630)
Net change in Southern Lights project financing	**(5)**	(13)	(62)
Debenture and term note issues	**2,845**	2,199	1,604
Debenture and term note repayments	**(660)**	(349)	(234)
Repayment of acquired debt	**-**	(160)	-
Contributions from noncontrolling interests	**922**	448	873
Distributions to noncontrolling interests	**(468)**	(421)	(355)
Contributions from redeemable noncontrolling interests	**92**	213	210
Distributions to redeemable noncontrolling interests	**(72)**	(49)	(35)
Preference shares issued	**1,428**	2,634	926
Common shares issued	**628**	465	46
Preference share dividends	**(178)**	(93)	(7)
Common share dividends	**(674)**	(597)	(530)
	5,070	4,395	2,030
Effect of translation of foreign denominated cash and cash equivalents	**20**	(12)	25
Increase/(decrease) in cash and cash equivalents	**(1,000)**	1,053	347
Cash and cash equivalents at beginning of year	**1,776**	723	376
Cash and cash equivalents at end of year	**776**	1,776	723
Cash and cash equivalents - discontinued operations	**(20)**	-	-
Cash and cash equivalents - continuing operations	**756**	1,776	723
Supplementary cash flow information			
Income taxes (received)/paid	**107**	267	(28)
Interest paid	**1,097**	988	955

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2013**	2012
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**756**	1,776
Restricted cash	**34**	19
Accounts receivable and other *(Note 8)*	**4,956**	4,014
Accounts receivable from affiliates	**65**	12
Inventory *(Note 9)*	**1,115**	779
Assets held for sale *(Note 10)*	**24**	-
	6,950	6,600
Property, plant and equipment, net *(Note 10)*	**42,279**	33,318
Long-term investments *(Note 12)*	**4,212**	3,175
Deferred amounts and other assets *(Note 13)*	**2,662**	2,461
Intangible assets, net *(Note 14)*	**1,004**	817
Goodwill *(Note 15)*	**445**	419
Deferred income taxes *(Note 24)*	**16**	10
	57,568	46,800
Liabilities and equity		
Current liabilities		
Bank indebtedness	**338**	479
Short-term borrowings *(Note 17)*	**374**	583
Accounts payable and other *(Note 16)*	**6,664**	5,052
Accounts payable to affiliates	**46**	-
Interest payable	**228**	196
Environmental liabilities *(Note 29)*	**260**	107
Current maturities of long-term debt *(Note 17)*	**2,811**	652
Liabilities held for sale *(Note 10)*	**7**	-
	10,728	7,069
Long-term debt *(Note 17)*	**22,357**	20,203
Other long-term liabilities *(Note 18)*	**2,938**	2,541
Deferred income taxes *(Note 24)*	**2,925**	2,483
Liabilities held for sale *(Note 10)*	**57**	-
	39,005	32,296
Commitments and contingencies *(Note 29)*		
Redeemable noncontrolling interests *(Note 19)*	**1,053**	1,000
Equity		
Share capital *(Note 20)*		
Preference shares	**5,141**	3,707
Common shares (831 and 805 outstanding at December 31, 2013 and 2012, respectively)	**5,744**	4,732
Additional paid-in capital	**746**	522
Retained earnings	**2,550**	3,173
Accumulated other comprehensive loss *(Note 22)*	**(599)**	(1,762)
Reciprocal shareholding *(Note 12)*	**(86)**	(126)
Total Enbridge Inc. shareholders' equity	**13,496**	10,246
Noncontrolling interests *(Note 19)*	**4,014**	3,258
	17,510	13,504
	57,568	46,800

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

Approved by the Board of Directors:

"signed"
David A. Arledge
Chair

"signed"
David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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

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

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

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

Investments in natural gas pipelines include the Company's interests in the United States portion of the Alliance System (Alliance Pipeline US), the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance System. The energy services businesses undertake physical commodity marketing activities and logistical services, refinery supply services and manage the Company's volume commitments on the Alliance System, Vector and other pipeline systems.

SPONSORED INVESTMENTS
Sponsored Investments includes the Company's 20.6% (2012 - 21.8%) ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% (2012 - 66.7%) investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership and an overall 67.3% (2012 - 67.7%) economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge, through its subsidiaries, manages the day-to-day operations of and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 6)*; unbilled revenues *(Note 8)*; allowance for doubtful accounts *(Note 8)*; depreciation rates and carrying value of property, plant and equipment *(Note 10)*; amortization rates of intangible assets *(Note 14)*; measurement of goodwill *(Note 15)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Note 23)*; provisions for income taxes *(Note 24)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 25)*; commitments and contingencies *(Note 29)*; fair value of asset retirement obligations (ARO); and estimates of losses related to environmental remediation obligations *(Note 29)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and a variable interest entity (VIE) for which the Company is the primary beneficiary. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships. For certain investments where the Company retains an undivided interest in assets and liabilities, Enbridge records its proportionate share of assets, liabilities, revenues and expenses.

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

REGULATION

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

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

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

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 4)*.

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

REVENUE RECOGNITION

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

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

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

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

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

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

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

Derivatives in Qualifying Hedging Relationships

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

Cash Flow Hedges

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

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

Fair Value Hedges

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

Net Investment Hedges

The Company uses net investment hedges to manage its exposure to changes in the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a disposal of the foreign operation.

Classification of Derivatives

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

INTANGIBLE ASSETS

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

GOODWILL

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

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

IMPAIRMENT

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

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

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

ASSET RETIREMENT OBLIGATIONS

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

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

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

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

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

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

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

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

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

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

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

STOCK-BASED COMPENSATION

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

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

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

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

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

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

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.

Presentation of Unrecognized Tax Benefits

Effective December 31, 2013, the Company elected to early adopt ASU 2013-11, which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

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.

4. 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 (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 revised 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.

The previously reported figures presented below exclude the effect of any subsequent presentation changes associated with discontinued operations. Comparative figures as at December 31, 2012 and for the years ended December 31, 2012 and 2011 have been revised throughout these financial statements as necessary to reflect these revisions.

	Year ended December 31, 2012			Year ended December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(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

	As at December 31, 2012		
	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)			
Long-term investments	3,386	(211)	3,175
Deferred amounts and other assets	2,622	(161)	2,461
Deferred income tax liabilities	2,601	(118)	2,483
Retained earnings	3,464	(291)	3,173
Accumulated other comprehensive loss	(1,799)	37	(1,762)

5. SEGMENTED INFORMATION

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

Year ended December 31, 2012	Liquids Pipelines[2]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3]	Sponsored Investments[2]	Corporate[1,3]	Consolidated
(millions of Canadian dollars)						
Revenues	2,445	2,438	13,106	6,671	-	24,660
Commodity and gas distribution costs	-	(1,220)	(13,676)	(4,283)	-	(19,179)
Operating and administrative	(942)	(528)	(142)	(1,076)	(51)	(2,739)
Depreciation and amortization	(399)	(336)	(57)	(431)	(13)	(1,236)
Environmental costs, net of recoveries	-	-	-	88	-	88
	1,104	354	(769)	969	(64)	1,594
Income/(loss) from equity investments	46	-	141	55	(47)	195
Other income/(expense)	(7)	83	33	49	80	238
Interest income/(expense)	(250)	(164)	(50)	(397)	20	(841)
Income taxes recovery/(expense)	(192)	(66)	269	(169)	(13)	(171)
Earnings/(loss) from continuing operations	701	207	(376)	507	(24)	1,015
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(123)	-	-	(123)
Income taxes recovery from discontinued operations	-	-	44	-	-	44
Loss from discontinued operations	-	-	(79)	-	-	(79)
Earnings/(loss)	701	207	(455)	507	(24)	936
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	(1)	(224)	-	(229)
Preference share dividends	-	-	-	-	(105)	(105)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	697	207	(456)	283	(129)	602
Additions to property, plant and equipment[4]	1,927	445	933	1,886	4	5,195
Total assets	15,124	7,416	5,349	15,648	3,263	46,800

Year ended December 31, 2011	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	1,934	2,516	13,343	8,996	-	26,789
Commodity and gas distribution costs	-	(1,282)	(12,814)	(6,812)	-	(20,908)
Operating and administrative	(752)	(508)	(116)	(847)	(36)	(2,259)
Depreciation and amortization	(364)	(320)	(68)	(383)	(12)	(1,147)
Environmental costs, net of recoveries	-	-	-	116	-	116
	818	406	345	1,070	(48)	2,591
Income/(loss) from equity investments	5	-	179	54	(5)	233
Other income/(expense)	31	(12)	39	68	(10)	116
Interest expense	(256)	(166)	(56)	(350)	(100)	(928)
Income taxes recovery/(expense)	(125)	(54)	(178)	(171)	5	(523)
Earnings/(loss) from continuing operations	473	174	329	671	(158)	1,489
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(9)	-	-	(9)
Income taxes recovery from discontinued operations	-	-	3	-	-	3
Loss from discontinued operations	-	-	(6)	-	-	(6)
Earnings/(loss) before extraordinary loss	473	174	323	671	(158)	1,483
Extraordinary loss, net of tax	-	(262)	-	-	-	(262)
Earnings/(loss)	473	(88)	323	671	(158)	1,221
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	-	(1)	(403)	-	(407)
Preference share dividends	-	-	-	-	(13)	(13)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	470	(88)	322	268	(171)	801
Additions to property, plant and equipment[4]	909	478	959	1,157	27	3,530

1 Included within the Corporate segment was Interest income of $443 million (2012 - $336 million; 2011 - $239 million) charged to other operating segments.

2 In December 2012 and October 2011, certain crude oil storage and renewable energy assets were transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $33 million (2011 - $71 million) have not been reclassified among segments for presentation purposes.

3 Due to a change in organizational structure, effective January 1, 2013, for the year ended December 31, 2012 earnings of $1 million (2011 - nil) and additions to property, plant and equipment of $108 million (2011 - nil) were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.

4 Includes allowance for equity funds used during construction.

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

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Canada	**12,690**	11,629	11,852
United States	**20,228**	13,031	14,937
	32,918	24,660	26,789

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

Property, Plant and Equipment

December 31,	**2013**	2012
(millions of Canadian dollars)		
Canada	**22,865**	19,293
United States	**19,414**	14,025
	42,279	33,318

6. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS
A number of businesses within the Company are subject to regulation. The Company's significant regulated businesses and related accounting impacts are described below.

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

Prior to July 1, 2011, the effective date of the CTS, the Incentive Tolling Settlement (ITS) defined the methodology for calculation of tolls on the core component of the Canadian Mainline. Toll adjustments for variances from requirements defined in the ITS were filed annually with the regulator for approval, and regulatory assets and liabilities were recognized to the extent amounts were recoverable from or payable to customers through future rates. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

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

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

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

EGD's after-tax rate of return on common equity embedded in rates was 8.9% for the year ended December 31, 2013 (2012 - 8.4%) based on a 36% deemed common equity component of capital for regulatory purposes (2012 - 36%).

The 2013 Settlement established the right to recover an existing OPEB liability of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The gain was presented within Other income/(expense) on the Consolidated Statements of Earnings for the year ended December 31, 2012. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

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

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and currently sets tolls at the lower of market-based or cost of service rates. As at December 31, 2011, EGNB discontinued rate-regulated accounting due to amendments in the rate setting methodology enacted by the Government of New Brunswick, and consequently wrote-off a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million. The write-off of $262 million, net of tax, was presented as an extraordinary loss on the Consolidated Statements of Earnings for the year ended December 31, 2011.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	**727**	598
Tolling deferrals[2]	**(36)**	(33)
Recoverable income taxes[3]	**42**	40
Gas Distribution		
Deferred income taxes[4]	**214**	201
Transaction services deferral[5]	**(51)**	(26)
Future removal and site restoration reserves[6]	**(929)**	(882)
Pension plans and OPEB[7]	**94**	212
Sponsored Investments		
Deferred income taxes[1]	**28**	39
Transportation revenue adjustments[8]	**33**	19

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

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

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

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

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

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

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

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

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

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

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

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2013, cumulative costs relating to this consulting contract of $154 million (2012 - $144 million) were included in Property, plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

7. ACQUISITIONS AND DISPOSITIONS

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

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

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

Tonbridge Power Inc.
On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share. Tonbridge was included within the Corporate segment upon acquisition and was subsequently reclassified to the Gas Pipelines, Processing and Energy Services segment effective January 1, 2013, due to a change in organizational structure.

October 13,	2011
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Working capital deficiency	(5)
Property, plant and equipment	196
Intangible assets	17
Long-term debt	(182)
Other long-term liabilities	(21)
	5
Purchase price:	
Cash (net of $15 million cash acquired)	5

No revenues from Tonbridge were recognized in 2011 as the transmission line was not in service. A net loss of $1 million was recognized in earnings for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expense. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in earnings in 2011 had the acquisition occurred on January 1, 2011.

OTHER ACQUISITIONS AND DISPOSITIONS

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

In November 2012, Enbridge acquired certain sour gas gathering and compression facilities located in the Peace River Arch region of northwest Alberta (collectively, Pipestone and Sexsmith) for a purchase price of $118 million, which has been fully allocated to Property, plant and equipment. Pipestone and Sexsmith are currently in service or under construction and are presented within the Gas Pipelines, Processing and Energy Services segment.

In May 2012, Enbridge acquired the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for cash consideration of $27 million, increasing its ownership interest to 100%. The Company's interest in Greenwich was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in December 2012 *(Note 19)*.

In October 2011, the Company acquired the remaining 10% interest in Talbot Windfarm, LP (Talbot) for $28 million, increasing its ownership interest to 100%. The Company's interest in Talbot was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in October 2011.

Unaudited proforma consolidated revenues and earnings that give effect to all of the Company's other acquisitions as if they had occurred as of January 1 in the year of acquisition are not presented as the information would not be materially different from the information presented in the accompanying Consolidated Statements of Earnings.

8. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Unbilled revenues	**2,773**	2,289
Trade receivables	**1,215**	677
Taxes receivable	**200**	123
Regulatory assets	**54**	-
Short-term portion of derivative assets *(Note 23)*	**385**	383
Prepaid expenses and deposits	**123**	132
Current deferred income taxes *(Note 24)*	**120**	167
Dividends receivable	**26**	26
Other	**98**	266
Allowance for doubtful accounts	**(38)**	(49)
	4,956	4,014

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement), certain trade and accrued receivables (the Receivables) have been sold by certain of EEP's subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement, as amended on September 20, 2013 and again on December 2, 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 December 31, 2013, the value of trade and accrued receivables outstanding owned by the SPE totalled US$380 million ($404 million).

9. INVENTORY

December 31,	**2013**	2012
(millions of Canadian dollars)		
Natural gas	**527**	448
Other commodities	**588**	331
	1,115	779

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $4 million (2012 - $10 million; 2011 - $9 million) for the year ended December 31, 2013 to reduce the cost basis of inventory to market value.

10. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2013**	2012
(millions of Canadian dollars)			
Liquids Pipelines			
Pipeline	2.6%	**8,974**	8,249
Pumping equipment, buildings, tanks and other	3.0%	**6,248**	5,094
Land and right-of-way	2.2%	**253**	225
Under construction	-	**4,846**	1,675
		20,321	15,243
Accumulated depreciation		**(3,838)**	(3,432)
		16,483	11,811
Gas Distribution			
Gas mains, services and other	3.8%	**8,020**	7,583
Land and right-of-way	1.1%	**79**	79
Under construction	-	**179**	102
		8,278	7,764
Accumulated depreciation		**(2,074)**	(1,912)
		6,204	5,852
Gas Pipelines, Processing and Energy Services			
Pipeline	3.5%	**1,013**	544
Wind turbines, solar panels and other	4.4%	**1,092**	519
Power transmission[1]	2.1%	**384**	29
Land and right-of-way	4.3%	**6**	6
Under construction[1]	-	**1,233**	1,761
		3,728	2,859
Accumulated depreciation		**(344)**	(350)
		3,384	2,509
Sponsored Investments			
Pipeline	2.9%	**8,979**	6,890
Pumping equipment, buildings, tanks and other	3.2%	**5,381**	4,787
Wind turbines, solar panels and other	3.7%	**2,243**	1,544
Land and right-of-way	2.3%	**755**	642
Under construction	-	**2,201**	2,002
		19,559	15,865
Accumulated depreciation		**(3,429)**	(2,770)
		16,130	13,095
Corporate			
Other[1]	12.7%	**84**	76
Under construction[1]	-	**36**	12
		120	88
Accumulated depreciation		**(42)**	(37)
		78	51
		42,279	33,318

1 Due to a change in organizational structure effective January 1, 2013, Property, plant and equipment of $313 million were reclassified from the Corporate segment to the Gas Pipelines and Energy Services segment for the year ended December 31, 2012.

Depreciation expense for the year ended December 31, 2013 was $1,282 million (2012 - $1,174 million; 2011 - $1,089 million).

GAS PIPELINES, PROCESSING AND ENERGY SERVICES
Impairment
In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Enbridge Offshore Pipelines (Offshore) assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas of the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

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

Discontinued Operations
During the fourth quarter of 2013, Enbridge concluded it would seek to dispose of certain assets within the Stingray corridor and entered into negotiations with an unrelated third party. As a result, at December 31, 2013, the related assets and liabilities were classified as held for sale and were measured at the lower of their carrying amount and estimated fair value less cost to sell which did not result in a fair value adjustment. The results of operations including revenues of $26 million (2012 - $32 million, 2011 - $19 million) and related cash flows have been presented as discontinued operations for the year ended December 31, 2013, with the prior year comparative figures reclassified. These amounts are included in the Gas Pipelines, Processing and Energy Services segment. The Company expects to complete the sale in the first quarter of 2014.

11. VARIABLE INTEREST ENTITY

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 67.3% (2012 - 67.7%; 2011 - 69.2%) economic interest, held indirectly through a common investment in ENF, a direct common trust unit investment in the Fund and a preferred unit investment in a wholly-owned subsidiary of the Fund. Enbridge also serves in the capacity of Manager of ENF, the Fund and its subsidiaries.

The summarized impact of the Company's interest in the Fund on earnings, cash flows and financial position is presented below. Earnings include the results of operations of certain assets acquired by the Fund from wholly-owned subsidiaries of Enbridge from the dates of acquisition of October 2011 and December 2012 *(Note 19)*. Earnings, cash flows and financial position information exclude the effect of intercompany transactions.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Revenues	**403**	288	146
Operating and administrative expense	**(126)**	(83)	(66)
Depreciation and amortization	**(130)**	(87)	(47)
Income from equity investments	**57**	54	57
Interest expense	**(91)**	(68)	(32)
Income taxes	**(27)**	(35)	(21)
Earnings	**86**	69	37
Loss attributable to noncontrolling interest	**24**	12	9
Earnings attributable to Enbridge	**110**	81	46
Cash flows			
Cash provided by operating activities	**260**	200	137
Cash used in investing activities	**(98)**	(160)	(95)
Cash provided by/(used in) financing activities	**(323)**	1,495	381
Increase/(decrease) in cash and cash equivalents	**(161)**	1,535	423

December 31,	**2013**	2012
(millions of Canadian dollars)		
Current assets	**84**	224
Property, plant and equipment, net	**2,317**	2,390
Long-term investments	**227**	215
Deferred amounts and other assets	**130**	145
Current liabilities	**(388)**	(250)
Long-term debt	**(1,364)**	(1,864)
Other long-term liabilities	**(26)**	(22)
Deferred income taxes	**(426)**	(404)
Net assets before noncontrolling interests	**554**	434

12. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2013**	2012
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Chicap Pipeline	43.8%	**29**	27
Mustang Pipeline	30.0%	**23**	21
Seaway Pipeline	50.0%	**2,048**	1,385
Gas Pipelines, Processing and Energy Services			
Offshore - various joint ventures	22.0% - 74.3%	**401**	391
Vector	60.0%	**125**	130
Alliance Pipeline US	50.0%	**201**	181
Aux Sable	42.7% - 50.0%	**306**	266
Other	33.3% - 70.0%	**11**	10
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**165**	179
Texas Express Pipeline	35.0%	**396**	183
Other	50.0%	**62**	35
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	**-**	-
Other	16.3% - 49.99%	**56**	55
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		**287**	246
Other		**102**	66
		4,212	3,175

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date which is comprised of $680 million (2012 - $636 million) in Goodwill and $517 million (2012 - $493 million) in amortizable assets.

JOINT VENTURES

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

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Revenues	**1,212**	956	827
Commodity costs	**(371)**	(236)	(138)
Operating and administrative expense	**(268)**	(244)	(200)
Depreciation and amortization	**(175)**	(159)	(158)
Other income/(expense)	**4**	4	(3)
Interest expense	**(74)**	(81)	(87)
Earnings before income taxes	**328**	240	241

December 31,	2013	2012
(millions of Canadian dollars)		
Current assets	**366**	299
Property, plant and equipment, net	**4,050**	3,192
Deferred amounts and other assets	**35**	26
Intangible assets, net	**75**	74
Goodwill	**680**	639
Current liabilities	**(395)**	(333)
Long-term debt	**(994)**	(895)
Other long-term liabilities	**(50)**	(194)
Net assets	**3,767**	2,808

Alliance Pipeline
Certain assets of Alliance Pipeline Canada are pledged as collateral to Alliance Pipeline Canada lenders and to the lenders of Alliance Pipeline US. As well, certain assets of Alliance Pipeline US are pledged as collateral to Alliance Pipeline US lenders and to the lenders of Alliance Pipeline Canada.

OTHER EQUITY INVESTMENTS
Noverco
At December 31, 2013, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2012 - 38.9%; 2011 - 38.9%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

At December 31, 2013, Noverco owned an approximate 3.9% (2012 - 6.0%; 2011 - 8.9%) reciprocal shareholding in common shares of Enbridge. The change in reciprocal shareholding compared with prior years reflected the sale of Enbridge common shares by Noverco in 2012 and 2013. Through secondary offerings, Noverco sold 22.5 million Enbridge common shares in 2012 and a further 15 million common shares in 2013. Enbridge’s share of the net after-tax proceeds of $297 million and $248 million were received as dividends from Noverco in May 2012 and June 2013, respectively. The transactions were recognized as issuances of treasury stock on the Consolidated Statements of Changes in Equity and as an operating activity on the Consolidated Statements of Cash Flows.

As a result of Noverco’s reciprocal shareholding in Enbridge common shares, the Company has an indirect pro-rata interest of 1.5% (2012 - 2.1%; 2011 - 3.5%) in its own shares. Both the equity investment in Noverco and shareholders’ equity have been reduced by the reciprocal shareholding of $86 million at December 31, 2013 (2012 - $126 million; 2011 - $187 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company’s investment in Noverco.

13. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	2013	2012
(millions of Canadian dollars)		
Regulatory assets	**1,172**	1,123
Long-term portion of derivative assets *(Note 23)*	**413**	408
Affiliate long-term note receivable *(Note 28)*	**185**	182
Contractual receivables	**356**	303
Deferred financing costs	**135**	127
Other	**401**	318
	2,662	2,461

At December 31, 2013, deferred amounts of $307 million (2012 - $265 million) were subject to amortization and are presented net of accumulated amortization of $159 million (2012 - $123 million). Amortization expense for the year ended December 31, 2013 was $34 million (2012 - $25 million; 2011 - $20 million).

14. INTANGIBLE ASSETS

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

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	11.9%	622	180	442
Natural gas supply opportunities	3.8%	291	50	241
Power purchase agreements	4.7%	85	4	81
Transportation agreements	2.9%	50	13	37
Other	5.6%	20	4	16
		1,068	251	817

Total amortization expense for intangible assets was $82 million (2012 - $64 million; 2011 - $58 million) for the year ended December 31, 2013. The Company expects aggregate amortization expense for the years ending December 31, 2014 through 2018 of $93 million, $83 million, $73 million, $65 million and $57 million, respectively.

15. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2012	48	-	30	362	-	440
Transfer of assets to the Fund	(29)	-	-	29	-	-
Foreign exchange and other	3	-	(17)	(7)	-	(21)
Balance at December 31, 2012	22	-	13	384	-	419
Foreign exchange and other	**1**	**-**	**1**	**24**	**-**	**26**
Balance at December 31, 2013	**23**	**-**	**14**	**408**	**-**	**445**

The Company did not recognize any goodwill impairments for the years ended December 31, 2013 and 2012.

16. ACCOUNTS PAYABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Operating accrued liabilities	**3,577**	2,729
Trade payables	**300**	123
Construction payables	**1,188**	568
Current derivative liabilities *(Note 23)*	**837**	1,075
Contractor holdbacks	**211**	86
Taxes payable	**176**	206
Security deposits	**65**	69
Other	**310**	196
	6,664	5,052

17. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2013**	2012
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.2%	2024	**200**	200
Medium-term notes[1]	4.8%	2015-2043	**2,985**	2,435
Southern Lights project financing[2]	2.7%	2014	**1,480**	1,413
Commercial paper and credit facility draws			**266**	25
Other[3]			**11**	12
Gas Distribution				
Debentures	9.9%	2024	**85**	85
Medium-term notes	5.3%	2014-2050	**2,702**	2,295
Commercial paper and credit facility draws			**374**	590
Sponsored Investments				
Junior subordinated notes[4]	8.1%	2067	**425**	398
Medium-term notes	3.9%	2014-2023	**1,615**	1,615
Senior notes[5]	6.3%	2014-2040	**4,201**	4,129
Commercial paper and credit facility draws[6]			**717**	1,405
Corporate				
United States dollar term notes[7]	4.2%	2015-2023	**2,393**	1,094
Medium-term notes	4.6%	2015-2042	**4,518**	4,268
Commercial paper and credit facility draws[8]			**3,598**	1,488
Other[9]			**(28)**	(14)
Total debt			**25,542**	21,438
Current maturities			**(2,811)**	(652)
Short-term borrowings[10]			**(374)**	(583)
Long-term debt			**22,357**	20,203

1 Included in medium-term notes is $100 million with a maturity date of 2112.
2 2013 - $352 million and US$1,061 million (2012 - $357 million and US$1,061 million).
3 Primarily capital lease obligations.
4 2013 - US$400 million (2012 - US$400 million).
5 2013 - US$3,950 million (2012 - US$4,150 million).
6 2013 - $41 million and US$635 million (2012 - $250 million and US$1,160 million).
7 2013 - US$2,250 million (2012 - US$1,100 million).
8 2013 - $2,476 million and US$1,055 million (2012 - $1,140 million and US$350 million).
9 Primarily debt discount.
10 Weighted average interest rate - 1.1% (2012 - 1.1%).

For the years ending December 31, 2014 through 2018, debenture and term note maturities are $1,330 million, $931 million, $1,393 million, $952 million, $960 million, respectively, and $13,562 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2014 through 2018 are $1,138 million, $1,088 million, $1,063 million, $988 million and $851 million, respectively. At December 31, 2013 and 2012, all debt is unsecured except for the Southern Lights project financing which is collateralized by the Southern Lights project assets of approximately $2,680 million (2012 - $2,565 million).

INTEREST EXPENSE

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Debentures and term notes	**1,123**	986	891
Commercial paper and credit facility draws	**34**	33	74
Southern Lights project financing	**40**	38	38
Capitalized	**(250)**	(216)	(75)
	947	841	928

CREDIT FACILITIES

		December 31, 2013			December 31, 2012
	Maturity Dates[2]	Total Facilities	Draws[3]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**266**	**34**	300
Gas Distribution	2014-2019	**713**	**382**	**331**	712
Sponsored Investments	2015-2018	**4,781**	**809**	**3,972**	3,162
Corporate	2015-2018	**11,805**	**3,651**	**8,154**	9,108
		17,599	**5,108**	**12,491**	13,282
Southern Lights project financing[1]	2014-2015	**1,570**	**1,498**	**72**	1,484
Total credit facilities		**19,169**	**6,606**	**12,563**	14,766

1 *Total facilities inclusive of $63 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.*

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 $4,580 million (2012 - $2,925 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

18. OTHER LONG-TERM LIABILITIES

December 31,	2013	2012
(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 6)*	**929**	882
Derivative liabilities *(Note 23)*	**1,395**	763
Pension and OPEB liabilities *(Note 25)*	**264**	573
Other	**350**	323
	2,938	2,541

19. NONCONTROLLING INTERESTS

December 31,	2013	2012
(millions of Canadian dollars)		
EEP	**2,810**	2,636
Enbridge Energy Management, L.L.C. (EEM)	**1,079**	498
EGD preferred shares	**100**	100
Other	**25**	24
	4,014	3,258

Noncontrolling interests in EEP represented the 79.4% (2012 - 78.2%) interest in EEP held by public unitholders, as well as interests of third parties in subsidiaries of EEP, including Midcoast Energy Partners, L.P. (MEP). The increase in noncontrolling interests in EEP included contributions of $372 million (US$355 million) received from an initial public offering (IPO) of MEP. In May 2013, EEP formed MEP, which at the time was EEP's wholly owned subsidiary, and transferred approximately 39% of its ownership interest in EEP's natural gas and NGL midstream business to MEP. In November 2013, MEP completed the IPO whereby a total of 21.3 million MEP's Class A common units were issued (including 2.8 million Class A common units issued pursuant to the exercise of the underwriters' over-allotment option in December 2013) representing approximately 46% limited partner interest in MEP.

During the year ended December 31, 2013, EEP also distributed $463 million (2012 - $419 million; 2011 - $353 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

During the year ended December 31, 2012, EEP completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests from 77.0% to 78.2%.The listed share issuance during the year ended December 31, 2012 resulted in contributions of $382 million (2011 - $695 million) from noncontrolling interest holders.

Noncontrolling interests in EEM represented the 88.3% (2012 - 83.2%) of the listed shares of EEM not held by the Company. The increase in noncontrolling interests reflected the issuance of listed shares in 2013 in which the Company did not participate and which resulted in contributions of $523 million from noncontrolling interest holders.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. EGD may, at is option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2013, no preferred shares have been redeemed.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Balance at beginning of year	**1,000**	640	362
Loss	**(24)**	(12)	(9)
Other comprehensive income/(loss)			
Change in unrealized gains/(loss) on cash flow hedges, net of tax	**4**	(1)	(3)
Comprehensive loss	**(20)**	(13)	(12)
Distributions to unitholders	**(72)**	(49)	(33)
Contributions from unitholders	**92**	225	170
Redemption value adjustment	**53**	197	153
Balance at end of year	**1,053**	1,000	640

Redeemable noncontrolling interests in the Fund at December 31, 2013 represented 68.6% (2012 - 67.7%; 2011 - 64.6%) of interests in the Fund's trust units that are held by third parties. During the year ended December 31, 2013, the Fund completed a unit issuance in which the Company did not participate, resulting in an increase in the redeemable noncontrolling interests from 67.7% to 68.6%. This resulted in contributions of $92 million from redeemable noncontrolling interest holders.

In December 2012, the Fund acquired Greenwich, Amherstburg and Tilbury solar energy projects, Hardisty Caverns and Hardisty Contract Terminals from Enbridge and wholly-owned subsidiaries of Enbridge for proceeds of $1.2 billion. In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for $1.2 billion. In both cases, ordinary trust units were issued by the Fund to partially finance these acquisitions, resulting in an increase in interests held by third parties in 2012 and 2011 and contributions from noncontrolling unitholders of $225 million and $170 million, respectively.

Distributions to noncontrolling unitholders were made on a monthly basis for the years ended December 31, 2013, 2012 and 2011 in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

20. SHARE CAPITAL

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

COMMON SHARES

December 31,	**2013** Number of Shares	**2013** Amount	2012 Number of Shares	2012 Amount	2011 Number of Shares	2011 Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**805**	**4,732**	781	3,969	770	3,683
Common Shares issued[1]	**13**	**582**	10	388	-	-
Dividend Reinvestment and Share Purchase Plan (DRIP)	**8**	**361**	8	297	7	229
Shares issued on exercise of stock options	**5**	**69**	6	78	4	57
Balance at end of year	**831**	**5,744**	805	4,732	781	3,969

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

PREFERENCE SHARES

December 31,	**2013** Number of Shares	**2013** Amount	2012 Number of Shares	2012 Amount	2011 Number of Shares	2011 Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	-	-
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**	-	-	-	-
Preference Shares, Series 7	**10**	**250**	-	-	-	-
Issuance costs		**(111)**		(78)		(19)
Balance at end of year		**5,141**		3,707		1,056

Characteristics of the preference shares are as follows:

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

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

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

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

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

5 *A cash dividend of $0.2381 per share will be payable on March 1, 2014 to Series 7 preference shareholders. The regular quarterly dividend of $0.275 per share will begin in the second quarter of 2014.*

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 15 million (2012 - 20 million; 2011 - 25 million), resulting from the Company's reciprocal investment in Noverco.

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

December 31,	**2013**	2012	2011
(number of common shares in millions)			
Weighted average shares outstanding	**806**	772	751
Effect of dilutive options	**11**	13	10
Diluted weighted average shares outstanding	**817**	785	761

For the year ended December 31, 2013, 6,327,500 anti-dilutive stock options (2012 - 5,733,000; 2011 - 48,000) with a weighted average exercise price of $44.85 (2012 - $38.32; 2011 - $32.02) were excluded from the diluted earnings per share calculation.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

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

SHAREHOLDER RIGHTS PLAN

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

21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 47 million have been issued to date. A further 52 million common shares have been reserved for issuance for the 2007 ISO and PBSO plans, of which seven million have been exercised and issued from treasury to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

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

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**27,368**	**25.69**		
Options granted	**6,369**	**44.85**		
Options exercised[1]	**(3,948)**	**20.10**		
Options cancelled or expired	**(187)**	**30.99**		
Options outstanding at end of year	**29,602**	**30.52**	**6.7**	**425**
Options vested at end of year[2]	**15,151**	**23.12**	**5.2**	**330**

1 The total intrinsic value of ISO exercised during the year ended December 31, 2013 was $98 million (2012 - $130 million; 2011 - $68 million) and cash received on exercise was $24 million (2012 - $69 million; 2011 - $56 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2013 was $22 million (2012 - $19 million; 2011 - $17 million).

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

Year ended December 31,	**2013**	2012	2011
Fair value per option *(Canadian dollars)*[1]	**5.27**	4.81	4.19
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	6
Expected volatility[3]	**17.4%**	19.7%	18.6%
Expected dividend yield[4]	**2.8%**	3.0%	3.4%
Risk-free interest rate[5]	**1.2%**	1.3%	2.9%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.15 (2012 - $4.65; 2011 - $4.01) for Canadian employees and US$5.63 (2012 - US$5.58; 2011 - US$5.11) for United States employees.*

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

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

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

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

Compensation expense recorded for the year ended December 31, 2013 for ISO was $27 million (2012 - $23 million; 2011 - $16 million). At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $37 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE BASED STOCK OPTIONS

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

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**6,704**	**29.56**		
Options exercised[1]	**(2,331)**	**18.29**		
Options outstanding at end of year	**4,373**	**35.56**	**5.7**	**41**
Options vested at end of year[2]	**830**	**19.44**	**1.6**	**21**

1 *The total intrinsic value of PBSO exercised during the year ended December 31, 2013 was $62 million (2012 - $20 million; 2011 - $2 million) and cash received on exercise was $28 million (2012 - $12 million; 2011 - $3 million).*

2 *The total fair value of options vested under the PBSO Plan during the year ended December 31, 2013 was nil (2012 - $1 million; 2011 - $2 million).*

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

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

1 The expected option term is based on historical exercise practice.
2 Expected volatility is determined with reference to historic daily share price volatility.
3 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
4 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.

Compensation expense recorded for the year ended December 31, 2013 for PBSO was $3 million (2012 - $2 million; 2011 - $2 million). At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $11 million. The cost is expected to be fully recognized over a weighted average period of approximately four years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two if the Company performs within the highest range of its performance targets. The 2011, 2012 and 2013 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2013 expense, multipliers of two, based upon multiplier estimates at December 31, 2013, were used for each of the 2011, 2012 and 2013 PSU grants.

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**652**		
Units granted	**259**		
Units matured[1]	**(346)**		
Dividend reinvestment	**26**		
Units outstanding at end of year	**591**	**1.5**	**54**

1 The total amount paid during the year ended December 31, 2013 for PSU was $48 million (2012 - $25 million; 2011 - $17 million).

Compensation expense recorded for the year ended December 31, 2013 for PSU was $25 million (2012 - $49 million; 2011 - $42 million). As at December 31, 2013, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $26 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

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

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**1,819**		
Units granted	**920**		
Units cancelled	**(36)**		
Units matured[1]	**(953)**		
Dividend reinvestment	**78**		
Units outstanding at end of year	**1,828**	**1.5**	**84**

1 *The total amount paid during the year ended December 31, 2013 for RSU was $41 million (2012 - $37 million; 2011 - $39 million).*

Compensation expense recorded for the year ended December 31, 2013 for RSU was $36 million (2012 - $32 million; 2011 - $31 million). As at December 31, 2013, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $46 million and is expected to be fully recognized over a weighted average period of approximately two years.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2013, 2012 and 2011, are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	**(621)**	**474**	**(1,265)**	**(26)**	**(324)**	**(1,762)**
Other comprehensive income/(loss) retained in AOCI	**707**	**(111)**	**487**	**11**	**165**	**1,259**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**134**	**-**	**-**	**-**	**-**	**134**
Commodity contracts[2]	**(1)**	**-**	**-**	**-**	**-**	**(1)**
Foreign exchange contracts[3]	**(8)**	**-**	**-**	**-**	**-**	**(8)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**-**	**-**	**-**	**-**	**36**	**36**
	832	**(111)**	**487**	**11**	**201**	**1,420**
Tax impact						
Income tax on amounts retained in AOCI	**(176)**	**15**	**-**	**-**	**(51)**	**(212)**
Income tax on amounts reclassified to earnings	**(36)**	**-**	**-**	**-**	**(9)**	**(45)**
	(212)	**15**	**-**	**-**	**(60)**	**(257)**
Balance at December 31, 2013	**(1)**	**378**	**(778)**	**(15)**	**(183)**	**(599)**

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

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB	Total
(millions of Canadian dollars)						
Balance at January 1, 2011	(66)	480	(1,245)	(11)	(142)	(984)
Other comprehensive income/(loss) retained in AOCI	(656)	(21)	78	(20)	(229)	(848)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	51	-	-	-	-	51
Commodity contracts[2]	43	-	-	-	-	43
Foreign exchange contracts[3]	1	-	-	-	-	1
Other contracts[4]	(2)	-	-	-	-	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	29	29
	(563)	(21)	78	(20)	(200)	(726)
Tax impact						
Income tax on amounts retained in AOCI	161	2	-	3	64	230
Income tax on amounts reclassified to earnings	(8)	-	-	-	(8)	(16)
	153	2	-	3	56	214
Balance at December 31, 2011	(476)	461	(1,167)	(28)	(286)	(1,496)

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

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market 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 2017 through execution of floating to fixed interest rate swaps with an average swap rate of 1.5%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018. A total of $10,419 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.8%.

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.

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 December 31, 2013 or 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.

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other *(Note 8)*						
Foreign exchange contracts	**16**	**11**	**51**	**78**	**(26)**	**52**
Interest rate contracts	**171**	**-**	**12**	**183**	**(27)**	**156**
Commodity contracts	**4**	**-**	**114**	**118**	**(64)**	**54**
Other contracts	**2**	**-**	**4**	**6**	**-**	**6**
	193	**11**	**181**	**385**	**(117)**	**268**
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	**7**	**33**	**27**	**67**	**(62)**	**5**
Interest rate contracts	**249**	**-**	**1**	**250**	**(47)**	**203**
Commodity contracts	**9**	**-**	**86**	**95**	**(67)**	**28**
Other contracts	**1**	**-**	**-**	**1**	**-**	**1**
	266	**33**	**114**	**413**	**(176)**	**237**
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	**(2)**	**(4)**	**(69)**	**(75)**	**26**	**(49)**
Interest rate contracts	**(387)**	**-**	**(16)**	**(403)**	**45**	**(358)**
Commodity contracts	**(14)**	**-**	**(345)**	**(359)**	**64**	**(295)**
	(403)	**(4)**	**(430)**	**(837)**	**135**	**(702)**
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	**(4)**	**(31)**	**(435)**	**(470)**	**62**	**(408)**
Interest rate contracts	**(68)**	**-**	**(1)**	**(69)**	**29**	**(40)**
Commodity contracts	**(2)**	**-**	**(854)**	**(856)**	**67**	**(789)**
	(74)	**(31)**	**(1,290)**	**(1,395)**	**158**	**(1,237)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**17**	**9**	**(426)**	**(400)**	**-**	**(400)**
Interest rate contracts	**(35)**	**-**	**(4)**	**(39)**	**-**	**(39)**
Commodity contracts	**(3)**	**-**	**(999)**	**(1,002)**	**-**	**(1,002)**
Other contracts	**3**	**-**	**4**	**7**	**-**	**7**
	(18)	**9**	**(1,425)**	**(1,434)**	**-**	**(1,434)**

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 *(Note 8)*						
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 *(Note 13)*						
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 *(Note 16)*						
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 *(Note 18)*						
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.

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

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.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**56**	(12)	(22)
Interest rate contracts	**814**	(46)	(724)
Commodity contracts	**(9)**	52	72
Other contracts	**(2)**	(3)	6
Net investment hedges			
Foreign exchange contracts	**(81)**	1	(26)
	778	(8)	(694)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	**(8)**	1	1
Interest rate contracts[2]	**107**	(1)	(10)
Commodity contracts[3]	**1**	(3)	(55)
Other contracts[4]	**-**	2	(2)
	100	(1)	(66)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**51**	23	11
Commodity contracts[3]	**(3)**	(3)	5
	48	20	16

1 *Reported within Other income/(expense) 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.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $135 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 48 months at December 31, 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.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(738)**	120	(179)
Interest rate contracts[2]	**(10)**	(2)	9
Commodity contracts[3]	**(496)**	(765)	280
Other contracts[4]	**(3)**	(2)	4
Total unrealized derivative fair value gains/(loss)	**(1,247)**	(649)	114

1 *Reported within Transportation and other services revenues (2013 - $352 million loss; 2012 - $150 million gain; 2011 - $77 million loss) and Other income/(expense) (2013 - $386 million loss; 2012 - $30 million loss; 2011 - $102 million loss) 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 (2013 - $375 million loss; 2012 - $681 million loss; 2011 - $216 million gain), Commodity costs (2013 - $35 million loss; 2012 - $21 million loss; 2011 - $61 million gain) and Operating and administrative expense (2013 - $86 million loss; 2012 - $63 million loss; 2011 - $3 million gain) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 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 *(Note 17)*.

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:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Canadian financial institutions	**230**	306
United States financial institutions	**227**	129
European financial institutions	**192**	244
Other[1]	**97**	128
	746	807

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

As at December 31, 2013, the Company had provided letters of credit totalling $81 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The

Company held $18 million of cash collateral on derivative asset exposures at December 31, 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. Within Gas Distribution, credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

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

Fair Value of Derivatives

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

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

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:

December 31, 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	4	Forward gas price	3.64	5.18	4.37	$/mmbtu[3]
Crude	1	Forward crude price	67.52	103.86	72.84	$/barrel
NGL	(8)	Forward NGL price	1.00	2.26	1.53	$/gallon
Power	(141)	Forward power price	43.50	67.67	57.62	$/MWH
Commodity contracts - physical[1]						
Natural gas	(22)	Forward gas price	3.36	5.29	4.18	$/mmbtu[3]
Crude	(10)	Forward crude price	64.73	113.19	92.15	$/barrel
NGL	4	Forward NGL price	0.02	2.68	1.59	$/gallon
Power	(1)	Forward power price	32.40	38.98	35.07	$/MWH
Commodity options[2]						
Natural gas	2	Option volatility	25%	31%	28%	
NGL	7	Option volatility	22%	44%	31%	
	(164)					

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

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

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

Year ended December 31,	**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]	**(100)**	(69)
Included in OCI	**-**	13
Settlements	**(40)**	-
Level 3 net derivative liability at end of period	**(164)**	(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 December 31, 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 totalled $103 million at December 31, 2013 (2012 - $66 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $287 million at December 31, 2013 (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 December 31, 2013, the fair value of this preferred share investment approximates its face value of $580 million (2012 - $580 million).

At December 31, 2013, the Company's long-term debt had a carrying value of $25,168 million (2012 - $20,855 million) and a fair value of $27,469 million (2012 - $24,809 million).

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes, discontinued operations and extraordinary loss	**613**	1,186	2,012
Canadian federal statutory income tax rate	**15%**	15%	16.5%
Expected federal taxes at statutory rate	**92**	178	332
Increase/(decrease) resulting from:			
Provincial and state income taxes	**(1)**	97	126
Foreign and other statutory rate differentials[1]	**45**	(69)	130
Effects of rate-regulated accounting	**(55)**	(38)	(15)
Foreign allowable interest deductions	**(39)**	(24)	(19)
Part VI.1 tax, net of federal Part I deduction[2]	**23**	19	1
Intercompany sale of investment[3]	**-**	33	59
Noncontrolling interests	**26**	(32)	(62)
Other[4]	**32**	7	(29)
Income taxes on earnings before discontinued operations and extraordinary loss	**123**	171	523
Effective income tax rate	**20.0%**	14.4%	26.0%

1 The effective income tax rate for 2012 reflected significant losses relating to certain risk management activities in the Company's United States operations and the higher United States federal statutory rate over the Canadian federal statutory rate. The losses did not persist to the same extent in 2013.

2 Represents Part VI.1 tax on preference share dividend distributions, net of an allowed federal deduction. For 2013, this tax was presented net of an $11 million federal tax recovery related to changes to tax law enacted during the year.

3 In December 2012 and October 2011, Enbridge and certain wholly-owned subsidiaries of Enbridge sold certain assets to the Fund. As these transactions occurred between entities under common control of the Company, the intercompany gains realized as a result of these transfers were eliminated, although tax expense of $56 million and $98 million remained as a charge to earnings in 2012 and 2011, respectively, of which the federal tax component was $33 million and $59 million. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying entities; however, accounting recognition of such benefit is not permitted until such time as the entities are sold outside of the consolidated group.

4 Other for 2013 includes $55 million related to the federal component of the tax effect of adjustments related to prior periods.

Comparative figures within the income tax reconciliation for 2012 and 2011 have been revised to conform to the presentation followed for the current year. In 2013, a preferable presentation format was adopted which calculates expected taxes using a federal statutory rate as opposed to a combined federal and provincial rate. This format is preferable as it is more commonly used by companies following U.S. GAAP.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes, discontinued operations and extraordinary loss			
Canada	**193**	1,037	683
United States	**132**	(58)	1,196
Other	**288**	207	133
	613	1,186	2,012
Current income taxes			
Canada	**(30)**	130	194
United States	**18**	35	(30)
Other	**4**	3	(6)
	(8)	168	158
Deferred income taxes			
Canada	**31**	160	30
United States	**100**	(157)	335
	131	3	365
Income taxes on earnings before discontinued operations and extraordinary loss	**123**	171	523

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,984)**	(1,289)
Investments	**(1,226)**	(1,397)
Regulatory assets	**(248)**	(221)
Other	**(115)**	(144)
Total deferred income tax liabilities	**(3,573)**	(3,051)
Deferred income tax assets		
Financial instruments	**487**	380
Pension and OPEB plans	**128**	180
Loss carryforwards	**129**	161
Other	**68**	51
Total deferred income tax assets	**812**	772
Less valuation allowance	**(28)**	(27)
Total deferred income tax assets, net	**784**	745
Net deferred income tax liabilities	**(2,789)**	(2,306)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 8)*	**120**	167
Deferred income taxes	**16**	10
Total deferred income tax assets	**136**	177
Liabilities		
Deferred income taxes	**(2,925)**	(2,483)
Total deferred income tax liabilities	**(2,925)**	(2,483)
Net deferred income tax liabilities	**(2,789)**	(2,306)

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2013, the Company recognized the benefit of unused tax loss carryforwards of $322 million (2012 - $183 million) in Canada which start to expire in 2029 and beyond.

As at December 31, 2013, the Company recognized the benefit of unused tax loss carryforwards of $34 million (2012 - $222 million) in the United States which expire in 2032.

The Company has not provided for deferred income taxes on $573 million (2012 - $548 million) of foreign subsidiaries' undistributed earnings as at December 31, 2013 as such earnings are intended to be indefinitely reinvested in the operations of these foreign subsidiaries. Upon distribution of these earnings in the form of dividends or otherwise, the Company would be subject to income taxes in the United States. It is not practicable to determine the income tax liability that might be incurred if these earnings were to be distributed.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Company is subject to potential examinations include the United States (federal and Texas) and Canada (federal, Alberta, Ontario and Quebec). The Company's 2006 and 2008 to 2013 taxation years are still open for audit in Canadian jurisdictions, whereas 2009 to 2013 taxation years are open for audit in United States jurisdictions. The Company is not currently under examination for income tax matters in any jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2013**	2012
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**54**	18
Gross increases for tax positions of current year	**10**	38
Gross increases/(decreases) for tax positions of prior years	**(14)**	3
Reduction for lapse of statute of limitations	**(4)**	(5)
Unrecognized tax benefits at end of year	**46**	54

The unrecognized tax benefits as at December 31, 2013, if recognized, would affect the Company's effective income tax rate. The gross increases for tax positions taken in the current year are in respect of the computation of Texas Margin Tax. The gross decreases for tax positions of prior years largely relates to filing positions that were based on substantively enacted legislation pertaining to Part VI.1 tax that became enacted in the second quarter of 2013.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income tax expense for the year ended December 31, 2013 included a $5 million recovery (2012 - $1 million expense; 2011 - $1 million expense) of interest and penalties. The recovery of interest and penalties is substantially attributed to interest that was previously accrued on a filing position that is now statute-barred. As at December 31, 2013, interest and penalties of $5 million (2012 - $10 million) have been accrued.

25. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Canadian Plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States 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.

A measurement date of December 31, 2013 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2013, the mortality assumptions were revised for the Canadian Plans resulting in an increase to pension liabilities of $58 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2012	December 31, 2013
Gas Distribution	September 1, 2013	September 1, 2016
United States Plan	January 1, 2013	January 1, 2014

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2013**	2012	**2013**	2012
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,879**	1,686	**261**	243
Service cost	**103**	84	**9**	8
Interest cost	**79**	74	**11**	10
Employees' contributions	**-**	-	**1**	1
Actuarial (gains)/loss	**(110)**	106	**(40)**	14
Benefits paid	**(75)**	(64)	**(7)**	(8)
Effect of foreign exchange rate changes	**19**	(5)	**6**	(2)
Other	**8**	(2)	**(1)**	(5)
Benefit obligation at end of year	**1,903**	1,879	**240**	261
Change in plan assets				
Fair value of plan assets at beginning of year	**1,500**	1,355	**62**	54
Actual return on plan assets	**200**	117	**8**	5
Employer's contributions	**155**	97	**12**	13
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(75)**	(64)	**(7)**	(8)
Effect of foreign exchange rate changes	**13**	(3)	**5**	(1)
Other	**6**	(2)	**-**	(2)
Fair value of plan assets at end of year[1]	**1,799**	1,500	**81**	62
Underfunded status at end of year	**(104)**	(379)	**(159)**	(199)
Presented as follows:				
Deferred amounts and other assets	**6**	-	**-**	-
Accounts payable and other	**-**	-	**(5)**	(5)
Other long-term liabilities *(Note 18)*	**(110)**	(379)	**(154)**	(194)
	(104)	(379)	**(159)**	(199)

1 Assets of $27 million (2012 - $19 million) are held by the Company in trust accounts that back non-registered supplemental pension plans benefitting United States plan participants. Due to United States tax regulations, these assets are not restricted from creditors and therefore the Company is unable to include these balances in plan assets for accounting purposes. However, these assets are committed for the future settlement of non-registered supplemental pension plan obligations included in the underfunded status as at the end of the year.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**5.0%**	4.2%	4.5%	**4.9%**	4.0%	4.4%
Average rate of salary increases	**3.7%**	3.7%	3.5%			

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
(millions of Canadian dollars)						
Benefits earned during the year	**103**	84	61	**9**	8	6
Interest cost on projected benefit obligations	**79**	74	73	**11**	10	11
Expected return on plan assets	**(103)**	(93)	(92)	**(4)**	(3)	(3)
Amortization of prior service costs	**1**	2	2	**-**	-	1
Amortization of actuarial loss	**52**	51	25	**2**	2	1
Net defined benefit costs on an accrual basis	**132**	118	69	**18**	17	16
Defined contribution benefit costs	**4**	4	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**136**	122	73	**18**	17	16
Amount recognized in OCI:						
Net actuarial (gains)/loss[1]	**(158)**	42	172	**(45)**	10	29
Net prior service cost/(credit)[2]	**-**	-	-	**2**	-	(1)
Total amount recognized in OCI	**(158)**	42	172	**(43)**	10	28
Total amount recognized in Comprehensive income	**(22)**	164	245	**(25)**	27	44

1 Unamortized actuarial losses included in AOCI, before tax, were $246 million (2012 - $388 million) relating to the pension plans and $11 million (2012 - $60 million) relating to OPEB at December 31, 2013.

2 Unamortized prior service costs included in AOCI, before tax, were $6 million (2012 - $4 million) relating to OPEB at December 31, 2013.

The Company estimates that approximately $12 million related to pension plans and $1 million related to OPEB at December 31, 2013 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 6)*. For the year ended December 31, 2013, an offsetting regulatory asset of $3 million (2012 - $22 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**4.2%**	4.5%	5.6%	**4.0%**	4.4%	5.6%
Average rate of return on pension plan assets	**6.7%**	7.1%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.5%	3.5%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.3%	4.5%	2029
Other Medical	4.5%	-	-
United States Plan	7.4%	4.5%	2030

A 1% increase in the assumed medical care trend rate would result in an increase of $30 million in the benefit obligation and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $25 million in the benefit obligation and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2013**	2012	**2013**	2012
Canadian Plans	**6.6%**	6.9%		
United States Plan	**7.2%**	7.3%	**6.0%**	6.0%

Target Mix for Plan Assets

	Canadian Plans		
	Liquids Pipelines Plan	Gas Distribution Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2013, the pension assets were invested 58.0% (2012 - 59.1%) in equity securities, 31.0% (2012 - 32.4%) in fixed income securities and 11.0% (2012 - 8.5%) in other. The OPEB assets were invested 59.3% (2012 - 58.1%) in equity securities, 38.3% (2012 - 35.5%) in fixed income securities and 2.4% (2012 - 6.4%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $1 million asset (2012 - $15 million liability) and refundable tax assets of $85 million (2012 - $76 million) have been excluded from the table below.

December 31,	2013 Level 1[1]	2013 Level 2[2]	2013 Level 3[3]	2013 Total	2012 Level 1[1]	2012 Level 2[2]	2012 Level 3[3]	2012 Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**42**	**-**	**-**	**42**	44	-	-	44
Fixed income securities								
Canadian government bonds	**99**	**-**	**-**	**99**	87	-	-	87
Corporate bonds and debentures	**3**	**4**	**-**	**7**	-	4	-	4
Canadian corporate bond index fund	**216**	**-**	**-**	**216**	196	-	-	196
Canadian government bond index fund	**167**	**-**	**-**	**167**	152	-	-	152
United States debt index fund	**69**	**-**	**-**	**69**	45	2	-	47
Equity								
Canadian equity securities	**128**	**-**	**-**	**128**	190	-	-	190
United States equity securities	**32**	**-**	**-**	**32**	24	-	-	24
Global equity securities	**11**	**-**	**-**	**11**	9	-	-	9
Canadian equity funds	**216**	**-**	**-**	**216**	64	39	-	103
United States equity funds	**152**	**33**	**-**	**185**	60	26	-	86
Global equity funds	**310**	**111**	**-**	**421**	255	159	-	414
Infrastructure[4]	**-**	**-**	**50**	**50**	-	-	61	61
Real estate[5]	**-**	**-**	**76**	**76**	-	-	24	24
Forward currency contracts	**-**	**(6)**	**-**	**(6)**	-	(2)	-	(2)
OPEB								
Cash and cash equivalents	**2**	**-**	**-**	**2**	4	-	-	4
Fixed income securities								
United States government and government agency bonds	**31**	**-**	**-**	**31**	22	-	-	22
Equity								
United States equity funds	**24**	**-**	**-**	**24**	17	19	-	36
Global equity funds	**24**	**-**	**-**	**24**	-	-	-	-

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investments in Bentall Kennedy Prime Canadian Property Fund Ltd and AEW Core Property Trust are established through the use of valuation models.

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

	2013	2012
(millions of Canadian dollars)		
Balance at beginning of year	**85**	68
Unrealized and realized gains	**7**	11
Purchases and settlements, net	**34**	6
Balance at end of year	**126**	85

Plan Contributions by the Company

Year ended December 31,	Pension **2013**	Pension 2012	OPEB **2013**	OPEB 2012
(millions of Canadian dollars)				
Total contributions	**155**	97	**12**	13
Contributions expected to be paid in 2014	**152**		**11**	

Benefits Expected to be Paid by the Company

Year ended December 31,	2014	2015	2016	2017	2018	2019-2023
(millions of Canadian dollars)						
Expected future benefit payments	80	85	90	95	101	591

26. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(272)**	71	48
Allowance for equity funds used during construction	**1**	1	3
Interest income on affiliate loans	**23**	20	17
Interest income	**4**	7	3
Noverco preferred shares dividend income	**40**	42	30
Gain on disposition *(Note 7)*	**18**	-	-
OPEB recovery *(Note 6)*	**-**	89	-
Other	**51**	8	15
	(135)	238	116

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Accounts receivable and other	**(789)**	(122)	121
Accounts receivable from affiliates	**(53)**	43	(17)
Inventory	**(315)**	42	93
Deferred amounts and other assets	**(25)**	(380)	(322)
Accounts payable and other	**832**	(319)	421
Accounts payable to affiliates	**46**	(48)	41
Interest payable	**25**	15	7
Other long-term liabilities	**(130)**	109	57
	(409)	(660)	401

28. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements were $6 million for the year ended December 31, 2013 (2012 - $6 million; 2011 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services have transportation commitments with several joint venture affiliates that are accounted for using the equity method. Total amounts charged for transportation services for the year ended December 31, 2013 were $222 million (2012 - $127 million; 2011 - $106 million).

Additionally, certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services made natural gas purchases of $99 million (2012 - $15 million; 2011 - nil) and sales of $10 million (2012 - $7 million; 2011 - $5 million) with several joint venture affiliates during the year ended December 31, 2013.

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector totalling $181 million (2012 - $178 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates ranging from 3% to 8%.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts that primarily relate to the purchase of services, pipe and other materials, as well as transportation, totalling $10,232 million which are expected to be paid within the next five years and $3,115 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $817 million in aggregate. Estimated annual lease payments for the years ending December 31, 2014 through 2018 are $116 million, $111 million, $108 million, $98 million and $52 million, respectively, and $332 million thereafter. Total rental expense for operating leases, included in Operating and administrative expense, were $49 million, $31 million and $28 million for the years ended December 31, 2013, 2012 and 2011, respectively.

ENVIRONMENTAL LIABILITIES

As at December 31, 2013, the Company had $260 million (2012 - $107 million) included in current liabilities and $27 million (2012 - $18 million) included in Other long-term liabilities which have been accrued for costs incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain liquids and natural gas assets and known fines or penalties.

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 20.6% (2012 - 21.8%; 2011 - 23.0%) combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA will again consider the status of the pipeline in light of information they acquire throughout 2014.

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

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

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

As at December 31, 2013, EEP's total cost estimate for the Line 6B crude oil release was US$1,122 million ($181 million after-tax attributable to Enbridge) which is an increase of US$302 million ($44 million after-tax attributable to Enbridge) compared to the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties other than US$30 million discussed below. On March 14, 2013, EEP received an order from the 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. EEP has currently completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta. EEP is in the process of working with the EPA to ensure this work is completed as soon as reasonably possible, inclusive of obtaining the necessary state and local permitting that is required and considering weather conditions.

Of the US$302 million increase compared with December 31, 2012 related to the Line 6B crude oil release, US$280 million is primarily related to additional work required by the Order including further refinement and definition of the additional dredging scope per the Order and all associated environmental, permitting, waste removal and other related costs, as well as increased dredge activity in and around Morrow Lake and the delta area. 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 December 31, 2013 exceeded the limits of the Company's insurance coverage. The remaining increase of US$22 million reflected an estimate of the minimum amount of civil penalties EEP may be assessed under the Clean Water Act of the United States (Clean Water Act) in respect of the Line 6B crude oil release.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 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

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

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, 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 December 31, 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. For the years ended December 31, 2013 and 2012, EEP recognized US$42 million ($6 million after-tax attributable to Enbridge) and US$170 million ($24 million after-tax attributable to Enbridge), respectively, of insurance recoveries as reductions to Environmental costs in the Consolidated Statements of Earnings. As at December 31, 2013, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release, out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable. In March 2013, the Company filed a lawsuit against one insurer who is disputing recovery eligibility for Line 6B costs. While the Company believes outstanding claims are covered under the policy, there can be no assurance that the Company 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 Lines 6A and 6B crude oil releases. 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, the Company does not expect the outcome of these actions to be material.

As at December 31, 2013, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by PHMSA that EEP paid during the third quarter of 2012. The total also included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties are ongoing.

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

TAX MATTERS

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

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

30. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

The Company has also agreed to indemnify the Fund for certain liabilities relating to environmental matters arising from operations prior to the transfer of certain crude oil storage assets to the Fund in 2012.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities. The Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.