ENBRIDGE INC
Form 6-K
August 02, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

Pursuant to Rule 13a-16 or 15d-16 of

the Securities Exchange Act of 1934

Dated August 2, 2012

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Canada	**None**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

Indicate by check mark whether the Registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F	Form 40-F	P

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes	No	P

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by regulation S-T Rule 101(b)(7):

Yes	No	P

Indicate by check mark whether the Registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No P

If Yes is marked, indicate below the file number assigned to the Registrant in connection with Rule 12g3-2(b):

N/A

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 33-77022) AND FORM F-10 (FILE NO. 333-181333) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Press Release dated August 2, 2012
- Interim Report to Shareholders for the six months ended June 30, 2012.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: August 2, 2012	By: /s/ Alison T. Love
	Alison T. Love
	Vice President & Corporate Secretary

NEWS RELEASE

Enbridge reports second quarter adjusted earnings of $277 million or $0.36 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- Second quarter earnings were $11 million; six month earnings were $275 million including unrealized non-cash mark-to-market losses

- Second quarter and six months adjusted earnings increased 7% to $277 million and 11% to $653 million, respectively

- Enbridge announced $3.2 billion of additional Eastern Access and Mainline Expansion projects

- Seaway Pipeline reversal was completed providing an initial 150,000 barrels per day of crude oil transportation capacity from Cushing, Oklahoma to the United States Gulf Coast

- Enbridge continued the execution of its financing plan with the issuance of $1.06 billion in preference shares, $0.4 billion in common shares and a unique $0.1 billion century bond with a term of 100 years

- Silver State North Solar Project and Greenwich Windfarm celebrated grand openings

- Enbridge responds to the National Transportation Safety Board report on the July 2010 Michigan crude oil release; and to the July 27, 2012 crude oil release in Wisconsin

CALGARY, ALBERTA, August 2, 2012 Enbridge Inc. (TSX:ENB) (NYSE:ENB) Over the first half of 2012, Enbridge has continued to deliver steady performance, keeping us on track with our full year adjusted earnings per share guidance range of $1.58 to $1.74, said Patrick D. Daniel, Chief Executive Officer.

2012 results reflected unrealized non-cash mark-to-market accounting impacts related to the comprehensive long-term economic hedging program Enbridge has put in place to mitigate exposures to interest rate variability and foreign exchange, as well as commodity price risks. These kinds of short-term non-cash impacts to reported earnings are a result of Enbridge s hedging program, which the Company believes over the long-term will support reliable cash flows and dividend growth.

In May, Enbridge announced a suite of major additions to its liquids pipelines infrastructure, totaling $3.2 billion. Enbridge has secured commercial support to proceed with additional Eastern Access projects including a 80,000 barrel per day (bpd) expansion of Enbridge s Toledo Pipeline (Line 17) and a re-reversal of Enbridge s 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec. Enbridge and Enbridge Energy Partners, L.P. (EEP) also expect to proceed with supporting expansions of the United States mainline system between Flanagan, Illinois and Sarnia, Ontario, and expansion of Line 67 (Alberta Clipper) and Line 61

(Southern Access).

Our Eastern Access projects complement our previously announced Gulf Coast Access projects in expanding access to new markets in North America for growing production from western Canada and the Bakken, said Mr. Daniel. These market access projects and the supporting mainline expansions are

Forward-Looking Information

This news release contains forward-looking information. Significant related assumptions and risk factors are described under the Forward-Looking Information section of this news release.

attractive investment opportunities for Enbridge and EEP. The associated aggregate investment of approximately $8 billion at attractive returns provides substantial support for the extension of our 10% growth rate in adjusted earnings per share through the middle of this decade and beyond.

Mr. Daniel noted that Enbridge s expansion projects will also provide substantial economic benefits to shippers and the local economies in western Canada and the Bakken region in North Dakota where the crude oil is produced, as well as in the midwestern United States and eastern Canada where it will be refined.

Communities along the routes of these pipelines will also benefit from increased economic activity. Importantly, these initiatives utilize existing energy corridors and pipelines that minimize disruption to the environment and lessen the industry s footprint.

Enbridge and its partner, Enterprise Products Partners, L.P. (Enterprise), marked a significant milestone with oil first flowing May 19, 2012 **on the reversed Seaway Pipeline for delivery to the United States Gulf Coast.**

We continue to make excellent progress in establishing a new and much needed corridor from the Chicago area to the United States Gulf Coast refining market, said Mr. Daniel. With the completion of the first phase of the reversal and expansion of the Seaway Pipeline we ve now added 150,000 bpd of new capacity out of the Cushing hub and we expect to ramp this up to 400,000 bpd by the beginning of 2013. Our Flanagan South Pipeline Project and existing Spearhead Pipeline System, combined with the planned twinning of the Seaway Pipeline, will bring total capacity from Chicago to the United States Gulf Coast to approximately 850,000 bpd by mid-2014, with low cost expandability beyond that. This will help to relieve bottlenecks arising from an unprecedented growth outlook for North American oil production, reduce price discounts for producers and further reduce United States dependence on overseas imports.

Over the quarter, Enbridge continued to be active in equity markets and building liquidity in support of the Company s suite of investment opportunities, placing approximately $610 million in preference shares; with a subsequent issue in July raising an additional $450 million. During the quarter, the Company was also successful in issuing 9.83 million common shares for gross proceeds of approximately $400 million.

In July, confidence in the long-term sustainability of Enbridge s business model was demonstrated by the issuance of a $100 million Century Bond with a 100-year term to maturity through its subsidiary, Enbridge Pipelines Inc., the second Century Bond ever issued by a Canadian corporation, said Mr. Daniel. Also in July, a new US$675 million credit facility was secured by EEP, bringing Enbridge s enterprise wide general purpose credit facilities to $11.8 billion.

In green energy, Enbridge celebrated grand openings at the Silver State North Solar Project (Silver State) in Nevada on May 7, 2012 and at the Greenwich Windfarm in Ontario on June 15, 2012.

We re pleased to continue to advance our growth strategy in renewable and alternative energy generation, creating environmental benefits while generating stable and reliable cash flows, said Mr. Daniel. Since 2002, Enbridge has invested nearly $3 billion in its growing North American portfolio of renewable and alternative energy technologies which now includes eight wind farms, four solar projects, a geothermal installation, a hybrid fuel cell and four waste heat recovery facilities.

Enbridge currently has in place the largest slate of attractive commercially secured growth projects in the history of the Company, supported by a team ready to execute and to lead the Company into the next stage of its development. As we enter the latter half of 2012, we remain confident in our ability to achieve our strategic objectives and to continue to deliver superior results to our shareholders, concluded Mr. Daniel.

In early July, the National Transportation and Safety Board (NTSB) issued a summary of its report on the July 2010 crude oil leak in Michigan, followed shortly after by publication of its final report.

On July 27, 2012, Enbridge confirmed a crude oil release on Line 14, owned by Enbridge Energy, Limited Partnership, a subsidiary of EEP, near Grand Marsh, Wisconsin. Enbridge continues to make significant clean up and restoration progress at the site and is committed to thorough restoration as quickly as possible. Repair of Line 14 is complete; however, the date for Line 14 to return to service is indeterminate at this time. Enbridge will work with the Pipeline and Hazardous Materials Safety Administration (PHMSA) to meet all requirements that must be satisfied prior to the restart of the line and will work with shippers to mitigate the impact of this disruption to the maximum extent possible.

At the time of the Marshall incident in July 2010, we immediately accepted full responsibility and committed to do whatever it took to make things right in the community, to fully understand what happened, and to do what was necessary to work with all parties to improve procedures and technology so that this wouldn t happen again, said Mr. Daniel. While we deeply regret the incident on Line 14 this past week, our ability to quickly detect and immediately respond to the leak thus limiting environmental impacts is evidence of our ongoing commitment to implement the learnings from 2010 and the enhancements we ve made over the past two years. We will continue to carefully examine the report of the NTSB, as well as the findings from the investigation of the Line 14 leak, to determine whether any further changes are required. We apologize to those affected by the Line 14 incident and we greatly appreciate the patience and cooperation of the affected landowners and the community.

Operational safety and reliability are our highest priorities, continued Mr. Daniel. We are humbled by the incidents we have experienced. Under the framework of our comprehensive Operational Risk Management plan, we are applying our learnings, and have set for ourselves the objective of delivering industry leading performance across all of our existing operations. We will design and build our growth projects to meet and exceed the expectations of our stakeholders for the safe and reliable delivery of energy.

SECOND QUARTER 2012 OVERVIEW

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

- Earnings attributable to common shareholders of $11 million for the second quarter of 2012 have decreased compared with the second quarter of 2011 primarily due to the recognition of net unrealized fair value losses on financial derivatives used to risk manage the profitability of forward transportation and storage transactions and revaluation of inventory in Energy Services, as well as foreign exchange and commodity price risks inherent within the Competitive Toll Settlement.

- Enbridge s second quarter adjusted earnings increased 7% to $277 million as a result of increased contributions from Canadian Mainline and Spearhead Pipeline, which benefited from strong volumes, partially offset by decreased earnings from Enbridge Gas New Brunswick (EGNB) and increased net Corporate segment financing costs.

- On July 27, 2012, a release of crude oil was detected on Line 14 of EEP s Lakehead System near Grand Marsh, Wisconsin. After detecting a pressure drop on Line 14, Line 14 was immediately shut down and isolated and emergency crews were promptly dispatched. The initial estimate of volume of the oil released was approximately 1,200 barrels. EEP estimates that its costs associated with repair of the pipeline and remediation of this crude oil release will be approximately US$8 million based on currently available information. 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. Enbridge received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012 and a follow on amendment to the CAO on August 1, 2012 outlining additional requirements that must be satisfied prior to the restart of Line 14. A substantial portion of the additional requirements are consistent with actions already planned and being implemented by Enbridge. Enbridge will review the requirements, adjust its plans as required, and work with PHMSA to satisfy all of the specified requirements on a timely basis. The date for Line 14 to return to service remains indeterminate until such work is further progressed. Enbridge will work with shippers to mitigate impacts to crude oil supply to midwestern United States refineries to the maximum extent possible. Enbridge does not anticipate the financial impact of a period of suspended service on Line 14 will be material.

• On July 10, 2012, theNTSB discussed the results of its investigation into the Line 6B crude oil release that occurred near Marshall, Michigan in July 2010 and subsequently posted its final report on July 26, 2012. Enbridge and EEP have worked closely and cooperatively with the NTSB throughout its investigation, and are now reviewing the report. Further on July 2, 2012, EEP and Enbridge received a Notice of Probable Violation (NOPV) from the PHMSA regarding this incident, which indicated a US$3.7 million civil penalty. Enbridge has worked closely and cooperatively with all federal and state agencies, including PHMSA, throughout the investigation of the Line 6B accident, and is now reviewing the NOPV in detail.

• On June 19, 2012, Enbridge confirmed an oil release at its Elk Point oil pumping station on Line 19 (Athabasca Pipeline), approximately 70 kilometres (44 miles) south of Bonnyville, Alberta and approximately 24 kilometres (15 miles) from the town of Elk Point. The release, which occurred June

18, 2012, was largely contained within the pumping station site with no risk to public health or safety. The area was secured and clean-up operations began immediately. Volume estimates of the release are approximately 1,400 barrels. After receiving approval from the Energy Resources Conservation Board (ERCB), Enbridge safely restarted the Elk Point pumping station on June 24, 2012. The ERCB and Enbridge are continuing their investigations as to the cause of the incident which appears to be the failure of a flange gasket.

• Enbridge and Renewable Energy Systems Canada Inc. (RES Canada), an affiliate of RES Americas, celebrated the grand opening of Enbridge s 99-megawatt (MW) Greenwich Windfarm on June 15, 2012. Located on the northern shore of Lake Superior, the 99 MW project is expected to generate enough clean electricity to meet the needs of about 34,000 households, potentially displacing about 107,000 tonnes of carbon dioxide emissions annually. It is the first wind power facility to be wholly located on Crown land in Ontario. The Greenwich Windfarm delivers energy to the Ontario Power Authority under a Renewable Energy Supply III (RES III) 20-year power purchase agreement. Comprising 43 Siemens SWT-2.3 wind turbines, the project was constructed by RES Canada under a fixed price, turnkey, engineering, procurement and construction agreement.

• Enbridge and Enterprise announced on May 19, 2012 that the Seaway Pipeline began accepting crude oil at Cushing, Oklahoma for delivery to the United States Gulf Coast. The reversal of the 805-kilometre (500-mile), 30-inch diameter pipeline, which had been in northbound service since 1995, provides North American producers with the infrastructure needed to access more than four million bpd of Gulf Coast refinery demand. The reversal will initially provide 150,000 bpd of capacity, which is expected to increase to more than 400,000 bpd in the first quarter of 2013 with additional modifications and increased pumping capabilities.

• On May 16, 2012, Enbridge announced it had secured commercial support to proceed with additional Eastern Access projects totaling up to approximately $2.6 billion. The Eastern Access initiative includes an 80,000 bpd expansion of the Toledo Pipeline, a reversal of the 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec and the previously announced reversal of Line 9A from Sarnia, Ontario to Westover. Enbridge and EEP also expect to proceed with supporting expansions of the United States mainline system between Flanagan, Illinois and Sarnia, Ontario. The supporting mainline expansions include expansion of the Spearhead North pipeline between Flanagan and Griffith, Indiana, an additional 330,000 barrel tank at Griffith, replacement of additional sections of Line 6B in Indiana and Michigan, as well as the previously announced Line 5 expansion.

• On May 16, 2012, Enbridge and EEP announced approximately US$0.4 billion of projects to expand capacity of the Lakehead System mainline between its origin near Neche, North Dakota, to its growing terminal hub in Flanagan, Illinois, southwest of Chicago. The current scope of the projects includes expansion of the Alberta Clipper pipeline (Line 67) between the border and Superior, Wisconsin from 450,000 bpd to 570,000 bpd and expansion of the Southern Access pipeline (Line 61) between Superior and Flanagan, Illinois from 400,000 bpd to 560,000 bpd. Both projects require only the addition of pumping horsepower, with no line pipe construction. The scope of the expansions remains under discussion with shippers, which could lead to an upward revision to capacity and cost.

• Also on May 16, 2012, Enbridge announced an approximately $0.2 billion expansion of the Canadian portion of the Alberta Clipper pipeline (Line 67). The current scope of the project will involve the addition of pumping horsepower sufficient to raise the capacity of the Canadian mainline by 120,000 bpd. The expansion remains subject to National Energy Board approval and to finalization of scope and approval by shippers, which could lead to an upward revision of capacity and cost.

- On May 7, 2012, Enbridge celebrated the grand opening of the 50-MW Silver State project in Clark County, Nevada. The facility was acquired in March 2012 at an estimated cost of US$0.2 billion. Located 65 kilometers (40 miles) south of Las Vegas, Nevada, Silver State was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar is providing operations and maintenance services under a long-term contract and the energy output is being delivered to NV Energy, Inc. under a 25-year power purchase agreement.

- On April 16, 2012, the Government of New Brunswick enacted a final rates and tariffs regulation which set limits on gas distribution rates within the province. Enbridge had advised on March 12, 2012, when the regulation was still in draft form, that it faced a potential write down of a significant portion of the value of its investment in EGNB, the New Brunswick gas distribution utility. With the finalization of the regulation, Enbridge confirmed a write down of $262 million. The impact of this charge was recognized as a subsequent event in the Company s 2011 United States generally accepted accounting principles (U.S. GAAP) consolidated financial statements, which were filed on May 2, 2012.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. The Application was heard by the Court on July 24, 2012, but no decision has yet been released. There is no assurance these actions will be successful or will result in any recovery.

- Since the end of the first quarter, the Company completed the following financing transactions:

- On July 18, 2012, Enbridge issued a $100 million Century Bond with a term to maturity of 100 years through its subsidiary, Enbridge Pipelines Inc., the second Century Bond ever issued by a Canadian corporation.

- On July 17, 2012, Enbridge completed an offering of Cumulative Redeemable Preference Shares, Series N. Due to strong investor demand, the size of the offering was increased to 18 million shares, for aggregate gross proceeds of $450 million.

- On July 6, 2012, a new US$675 million of credit facility was secured by EEP, bringing Enbridge s enterprise-wide general purpose credit facilities to $11.7 billion.

- On June 8, 2012, Enbridge completed a public offering of 9.83 million common shares for gross proceeds of approximately $400 million.

- On May 23, 2012, Enbridge completed an offering of Cumulative Redeemable Preference Shares, Series L. Due to strong investor demand, the size of the offering was increased to 16 million shares, for aggregate gross proceeds of US$400 million.

- On April 19, 2012, Enbridge announced the completion of the issue of eight million Cumulative Redeemable Preference Shares, Series J for aggregate gross proceeds of US$200 million.

DIVIDEND DECLARATION

On August 1, 2012, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2012 to shareholders of record on August 15, 2012.

Common Shares	$0.28250
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[1]	$0.42470
Preference Shares, Series J[2]	US$0.36990
Preference Shares, Series L[3]	US$0.27670

1 This is the first dividend declared for Preference Shares, Series H.

2 This is the first dividend declared for Preference Shares, Series J.

3 This is the first dividend declared for Preference Shares, Series L.

CONFERENCE CALL

Enbridge will hold a conference call on Thursday, August 2, 2012 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the second quarter 2012 results. Analysts, members of the media and other interested parties can access the call at 617-597-5313 or toll-free at 1-866-362-4666 using the access code of 40728322. The call will be audio webcast live at **www.enbridge.com/InvestorRelations/Events.aspx**. A webcast replay and podcast will be available approximately two hours after the conclusion of the event and a transcript will be posted to the website within 24 hours. The replay at toll-free 1-888-286-8010 or 617-801-6888 (access code 46996724) will be available until August 9, 2012.

The conference call will begin with presentations by the Company s Chief Executive Officer, the President and the Chief Financial Officer, followed by a question and answer period for investment analysts. A question and answer period for members of the media will then immediately follow.

The unaudited interim Consolidated Financial Statements and MD&A, which contain additional notes and disclosures, are available on the Enbridge website at www.enbridge.com/InvestorRelations.aspx.

Enbridge Inc., a Canadian company, is a North American leader in delivering energy and one of the Global 100 Most Sustainable Corporations. As a transporter of energy, Enbridge operates, in Canada and the U.S., the world s longest crude oil and liquids transportation system. The Company also has a significant and growing involvement in the 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. Enbridge employs more than 7,000 people, primarily in Canada and the U.S., and is ranked as one of Canada s Greenest Employers and one of the Top 100 Companies to Work for in Canada. Enbridge s common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit www.enbridge.com. None of the information contained in, or connected to, Enbridge s website is incorporated in or otherwise part of this news release.

Forward-Looking Information

Forward-looking information, or forward-looking statements, have been included in this news release 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 , 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 or adjusted earnings; expected earnings or adjusted earnings per share; 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 that 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 and natural gas liquids (NGL); prices of crude oil, natural gas and NGL; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project 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 and NGL, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, *may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction 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, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this news release 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 news release 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 news release contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company s dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers.

Enbridge Contacts:

Media
Jennifer Varey
(403) 508-6563 or Toll Free: 1-888-992-0997
Email: jennifer.varey@enbridge.com

Investment Community
Jody Balko
(403) 231-5720
Email: jody.balko@enbridge.com

HIGHLIGHTS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders				
Liquids Pipelines	**119**	197	**310**	333
Gas Distribution	**20**	40	**98**	142
Gas Pipelines, Processing and Energy Services	**(114)**	77	**(225)**	103
Sponsored Investments	**65**	64	**131**	119
Corporate	**(79)**	(76)	**(39)**	(31)
	11	302	**275**	666
Earnings per common share[1]	**0.01**	0.40	**0.36**	0.89
Diluted earnings per common share[1]	**0.01**	0.40	**0.35**	0.88
Adjusted earnings[2]				
Liquids Pipelines	**152**	124	**310**	260
Gas Distribution	**29**	38	**131**	129
Gas Pipelines, Processing and Energy Services	**45**	42	**81**	81
Sponsored Investments	**60**	56	**127**	109
Corporate	**(9)**	(2)	**4**	9
	277	258	**653**	588
Adjusted earnings per common share[1]	**0.36**	0.34	**0.86**	0.78
Cash flow data				
Cash provided by operating activities	**984**	696	**1,632**	1,859
Cash used in investing activities	**(1,475)**	(839)	**(2,403)**	(1,486)
Cash provided by/(used in) financing activities	**58**	130	**721**	(171)
Dividends				
Common share dividends declared	**217**	190	**438**	378
Dividends paid per common share[1]	**0.2825**	0.2450	**0.5650**	0.4900
Shares outstanding *(millions)*				
Weighted average common shares outstanding[1]	**770**	752	**763**	750
Diluted weighted average common shares outstanding[1]	**783**	762	**775**	760
Operating data				
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*				
Canadian Mainline[3]	**1,659**	1,459	**1,673**	1,532
Regional Oil Sands System[4]	**298**	291	**315**	310
Spearhead Pipeline	**175**	57	**160**	108
Gas Distribution - Enbridge Gas Distribution (EGD)				
Volumes *(billions of cubic feet)*	**66**	75	**227**	268
Number of active customers *(thousands)*[5]	**2,001**	1,971	**2,001**	1,971
Heating degree days[6]				
Actual	**416**	485	**1,906**	2,451
Forecast based on normal weather	**478**	495	**2,248**	2,297
Gas Pipelines, Processing and Energy Services -				
Average throughput volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,536**	1,519	**1,582**	1,601
Vector Pipeline	**1,423**	1,395	**1,588**	1,572
Enbridge Offshore Pipelines	**1,602**	1,732	**1,552**	1,741

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

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

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

4 Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.

5 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.

6 Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD s franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

June 30, 2012

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2012

This Management s Discussion and Analysis (MD&A) dated August 1, 2012 should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and six months ended June 30, 2012, prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements, which were prepared in accordance with Part V Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook (Part V), and MD&A contained in the Company s Annual Report for the year ended December 31, 2011, as well as the consolidated financial statements for the year ended December 31, 2011 that were prepared in accordance with U.S. GAAP and filed on a voluntary basis to facilitate understanding of the Company s transition to 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.

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**119**	197	**310**	333
Gas Distribution	**20**	40	**98**	142
Gas Pipelines, Processing and Energy Services	**(114)**	77	**(225)**	103
Sponsored Investments	**65**	64	**131**	119
Corporate	**(79)**	(76)	**(39)**	(31)
Earnings attributable to common shareholders	**11**	302	**275**	666
Earnings per common share1	**0.01**	0.40	**0.36**	0.89
Diluted earnings per common share1	**0.01**	0.40	**0.35**	0.88

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

Earnings attributable to common shareholders were $11 million for the three months ended June 30, 2012, or $0.01 per common share, compared with $302 million, or $0.40 per common share, for the three months ended June 30, 2011. This decrease primarily reflected the recognition of net unrealized fair value losses on financial derivatives compared with net unrealized gains for the prior period. The Company uses derivatives to manage exposures to interest rate variability and foreign exchange and commodity price risks. The most significant change, recognized in Energy Services, related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions, and revaluation of inventory. Partially offsetting these quarter-over-quarter declines were increased earnings from Liquids Pipelines as a result of strong volumes and favourable operating performance under the Competitive Toll Settlement (CTS).

Earnings attributable to common shareholders were $275 million for the six months ended June 30, 2012, or $0.36 per common share, compared with $666 million, or $0.89 per common share, for the six months ended June 30, 2011. The decrease in year-to-date earnings reflected the same drivers as the second quarter, with increased earnings from Enbridge Income Fund (the Fund) partially offsetting the decrease. This earnings increase primarily resulted from strong contributions from the Fund s increased investment in renewable assets.

1

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 sim 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 or adjusted earnings; expected earnings or adjusted earnings 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 and natural gas liquids (NGL); prices of crude oil, natural gas and NGL; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project 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 and NGL, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction 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, 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 non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company s dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**152**	124	**310**	260
Gas Distribution	**29**	38	**131**	129
Gas Pipelines, Processing and Energy Services	**45**	42	**81**	81
Sponsored Investments	**60**	56	**127**	109
Corporate	**(9)**	(2)	**4**	9
Adjusted earnings	**277**	258	**653**	588
Adjusted earnings per common share1	**0.36**	0.34	**0.86**	0.78

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

Adjusted earnings were $277 million, or $0.36 per common share, for the three months ended June 30, 2012 compared with $258 million, or $0.34 per common share, for the three months ended June 30, 2011. Adjusted earnings were $653 million, or $0.86 per common share, for the six months ended June 30, 2012 compared with $588 million, or $0.78 per common share, for the six months ended June 30, 2011. The following factors impacted the increase in adjusted earnings for both the three and six months ended June 30, 2012 compared with 2011.

- Within Liquids Pipelines, increased contributions from Canadian Mainline and Spearhead Pipeline, both of which benefited from strong volumes. Incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota have bolstered supply to midwest markets, and placed increased downward pressure on crude oil prices in the midwest, pending completion of Enbridge s market access projects. This discounted crude oil, coupled with strong refining margins, is increasing demand in the midwest for Canadian and Bakken crude oil supply and driving increased long haul barrels on Canadian Mainline and Enbridge Energy Partners, L.P. s (EEP) Lakehead System.

- Continued positive performance at Enbridge Gas Distribution (EGD) reflecting favourable operating performance under the current Incentive Regulation term was more than offset for the three months by decreased earnings from Other Gas Distribution and Storage, including from Enbridge Gas New Brunswick (EGNB). Under the new regulations to which EGNB is subject, rate regulated accounting no longer applies. EGNB earnings will be reduced and will fluctuate with variations in seasonal demand.

- EEP adjusted earnings primarily reflected higher volumes on all major liquids systems, offset for the three months by lower NGL prices.

- Increased contributions from the Fund due to the acquisition and strong operating performance of certain renewable energy assets, partially offset by increased financing costs and deferred income taxes.

- In Corporate, higher net Corporate segment financing costs, inclusive of preference share dividends.

RECENT DEVELOPMENTS

CHIEF EXECUTIVE OFFICER SUCCESSION PLANS

On February 27, 2012, the Board of Directors announced that Patrick D. Daniel, then President and Chief Executive Officer (CEO), will retire at or before the end of 2012. The Board also announced the appointment of Al Monaco, previously President, Gas Pipelines, Green Energy and International, to Enbridge s Board of Directors and to the position of President, effective February 27, 2012. Mr. Daniel will continue as CEO and a member of the Board until his retirement. With Mr. Monaco s appointment as President of Enbridge, Leon Zupan was appointed President, Gas Pipelines.

LIQUIDS PIPELINES

Southern Lights Pipeline

Both the Canadian and United States uncommitted rates on Southern Lights Pipeline for 2010, 2011 and 2012 were challenged by Exxon Mobil and Imperial Oil. The Canadian Southern Lights toll hearing was held before National Energy Board (NEB) panel members in November 2011. On February 9, 2012, the NEB issued its decision rejecting the challenge from uncommitted shippers stating that tolls in place are just and reasonable, and more recently approved the 2010, 2011 and 2012 interim tolls as final. A Federal Energy Regulatory Commission (FERC) hearing was held in January 2012. Briefs were filed on February 27, 2012 and March 28, 2012 and an initial decision was issued on June 5, 2012. The initial decision found that the uncommitted rates were just and reasonable. The parties will file briefs in response to this decision and the case will then be sent to the FERC for a final decision. No material financial impact to the Company is anticipated to result from the FERC proceeding.

Elk Point Pump Station Facility Oil Release

On June 19, 2012, Enbridge reported an oil release at its Elk Point pumping station on Line 19 (Athabasca Pipeline), approximately 70 kilometres (44 miles) south of Bonnyville, Alberta and approximately 24 kilometres (15 miles) from the town of Elk Point, Alberta. On June 24, 2012, the Company restarted the Elk Point pumping station after completing necessary repairs. The majority of contaminated soil and free product has been removed from the site for processing and disposal. Further environmental testing and monitoring of the site is being conducted. Volume estimates of the release are approximately 1,400 barrels which were largely contained within the station. Management does not believe this incident will have a material impact on the Company s consolidated financial position or results of operations.

Norman Wells Pipeline Crude Oil Release

On May 9, 2011, Enbridge reported a crude oil release from the Norman Wells Pipeline approximately 50 kilometres (31 miles) south of the community of Wrigley, Northwest Territories (NWT). The Norman Wells Pipeline is a 12-inch, 39,400 barrels per day (bpd) line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, Alberta. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Excavation of all contaminated soils from the spill site was completed in late November 2011. Based on the volume of contaminated materials removed from the site, the current estimate of volume released is approximately 1,600 barrels. Site reclamation work is anticipated to be completed in the summer of 2012. Monitoring of surface water and groundwater at the site will continue until remediation and reclamation goals have been achieved in accordance with plans filed with the regulator. Management does not believe this incident will have a material impact on the Company s consolidated financial position or results of operations.

GAS DISTRIBUTION

Enbridge Gas New Brunswick Regulatory Matters

On December 9, 2011 the Government of New Brunswick tabled and 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. However, significant details of the rate setting process were left to be established in the new regulations and, as such, the effect of such legislation was not determinable at that time.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amendments to the rate setting methodology outlined therein, EGNB no longer meets the criteria for the continuation of rate regulated accounting. As a result, the Company must eliminate 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, recognition of the charge totaling $262 million, after tax, was reflected as a subsequent event in the Company s U.S. GAAP consolidated financial statements for the year ended December 31, 2011, which were filed with the Canadian Securities Administrators and the United States Securities and Exchange Commission (SEC) on May 2, 2012. The charge reflects Management s best estimate based on facts available at this time and may be subject to further revision based on future actions or interpretations of the regulator, the Government of New Brunswick or other factors, including judicial proceedings which Enbridge has commenced, as referred to below.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. The Application was heard by the Court on July 24, 2012, but no decision has yet been released. There is no assurance these actions will be successful or will result in any recovery.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Greenwich Wind Energy Project

In May 2012, the Company acquired from Renewable Energy Systems Canada Inc. the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for $27 million, increasing its ownership to 100%.

SPONSORED INVESTMENTS

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP with its earnings, net of noncontrolling interests, reflected 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. After detecting a pressure drop on Line 14, Line 14 was immediately shut down and isolated and emergency crews were promptly dispatched. The initial estimate of volume of the oil released was approximately 1,200 barrels. EEP estimates that its costs associated with repair of the pipeline and remediation of this crude oil release will be approximately US$8 million based on currently available information. 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. Enbridge received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012 and a follow on amendment to the CAO on August 1, 2012 outlining additional requirements that must be satisfied prior to the restart of Line 14. A substantial portion of the additional requirements are consistent with actions already planned and being implemented by Enbridge. Enbridge will review the requirements, adjust its plans as required, and work with PHMSA to satisfy all of the specified requirements on a timely basis. The date for Line 14 to return to service remains indeterminate until such work is further progressed. Enbridge will work with shippers to mitigate impacts to crude oil supply to midwestern United States refineries to the maximum extent possible. Enbridge does not anticipate the financial impact of a period of suspended service on Line 14 will be material.

Lakehead System Line 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

During the second quarter of 2012, cleanup of the areas affected by the Line 6B crude oil release that occurred in July 2010 near Marshall, Michigan allowed the Kalamazoo River and Morrow Lake to be re-opened for recreational use. EEP will continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives that EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the PHMSA related to the Line 6B crude oil release, which indicated a US$3.7 million civil penalty. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety Board presented the results of its investigation into the Line 6B crude oil release and subsequently posted its final report on July 26, 2012.

As a result of additional work needed as noted above and the civil penalty assessed by PHMSA, EEP has revised the total estimate for costs to US$785 million ($131 million after-tax attributable to Enbridge) for this incident, before insurance recoveries, and excluding fines and penalties which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above, as at June 30, 2012, an increase of US$20 million ($2 million after-tax attributable to Enbridge) from March 31, 2012. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at June 30, 2012. 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

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. 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 in May of each year. The program 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 June 30, 2012, Enbridge and its affiliates have exceeded the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received insurance payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. At June 30, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP s insurance policies during the period that EEP deems realization of the claim for recovery to be probable. EEP recognized US$15 million ($3 million after-tax attributable to Enbridge) and US$50 million ($8 million after-tax attributable to Enbridge) of insurance recoveries for the three and six months ended June 30, 2011, respectively.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed 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 these actions to be material. On July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of US$3.7 million. 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 a United States state court. The parties are currently operating under an agreed interim order.

Enbridge Income Fund

Saskatchewan System Shipper Complaint

On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls interim effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Saskatchewan System was not adequate to allow for an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper s complaint. The NEB directed additional discussion among the parties and, as of August 1, 2012, the Fund continues to review the structure of its Westspur tolls with shippers.

CORPORATE

Noverco

Noverco Inc. (Noverco) holds, directly and indirectly, an investment in Enbridge common shares. In early 2012, Noverco advised Enbridge that the substantial increase in the value of these shares over the last decade resulted in a significant shift in the balance of Noverco s asset mix. The Board of Directors of Noverco authorized the Caisse de Depot et Placement de Quebec, as manager of Noverco, to sell a portion of its Enbridge common share holding and rebalance Noverco s asset mix. 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 . For United States tax purposes, the dividend was a qualified dividend .

Preference Share Issuances

Since January 1, 2012 the Company has issued 76 million preference shares for gross proceeds of approximately $1,910 million with the following characteristics. See *Outstanding Share Data.*

(Canadian dollars unless otherwise stated)	Gross Proceeds	Initial Yield	Dividend1	Per Share Base Redemption Value2	Redemption and Conversion Option Date2,3	Right to Convert Into3,4
Series F5	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H5	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J5	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L5	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O

1 *Fixed, cumulative, quarterly preferential dividend per share per year.*

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 + 2.51% (Series G), 2.12% (Series I) or 2.65% (Series O)), or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.05% (Series K) or 3.15% (Series M)).*

5 See *Liquidity and Capital Resources - Financing Activities for dividends declared on August 1, 2012.*

Common Share Issuance

On June 8, 2012, the Company issued 9.83 million Common Shares for gross proceeds of approximately $400 million.

7

GROWTH PROJECTS

The table below summarizes the current status of the Company s commercially secured projects in each of the Company s business segments.

			Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.	Edmonton Terminal Expansion		$0.3 billion	$0.1 billion	2012	Under construction
2.	Woodland Pipeline		$0.3 billion	$0.2 billion	2012	Substantially complete
3.	Wood Buffalo Pipeline		$0.4 billion	$0.3 billion	2012	Under construction
4.	Waupisoo Pipeline Capacity Expansion		$0.4 billion	$0.2 billion	2012-2013 (in phases)	Under construction
5.	Seaway Crude Pipeline System (including reversal, expansion and extension)		US$2.4 billion	US$1.2 billion	2012-2014 (in phases)	Under construction
6.	Norealis Pipeline		$0.5 billion	$0.1 billion	2013	Under construction
7.	Athabasca Pipeline Capacity Expansion		$0.4 billion	$0.1 billion	2013-2014 (in phases)	Under construction
8.	Eastern Access Expansion - Toledo expansion and Line 9 reversal	3	US$0.2 billion + $0.3 billion	No significant expenditures to date	Toledo - 2013 Line 9 - 2013-2014	Pre-construction
9.	Flanagan South Pipeline Project		US$2.8 billion	No significant expenditures to date	2014	Pre-construction
10.	Canadian Mainline Expansion		$0.2 billion	No significant expenditures to date	2014	Pre-construction
11.	Athabasca Pipeline Twinning		$1.2 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES						
12.	Silver State North Solar Project		US$0.2 billion	US$0.2 billion	2012	Complete
13.	Lac Alfred Wind Project		$0.3 billion	$0.2 billion	2012-2013 (in phases)	Under construction
14.	Cabin Gas Plant		$1.1 billion	$0.6 billion	2012-2014 (in phases)	Under construction
15.	Tioga Lateral Pipeline		US$0.1 billion	No significant expenditures to date	2013	Pre-construction
16.	Venice Condensate Stabilization Facility		US$0.2 billion	No significant expenditures to date	2013	Under construction
17.	Walker Ridge Gas Gathering System		US$0.4 billion	US$0.1 billion	2014	Pre-construction
18.	Big Foot Oil Pipeline		US$0.2 billion	US$0.1 billion	2014	Pre-construction

SPONSORED INVESTMENTS					
19.		EEP - Bakken Expansion Program	US$0.4 billion	US$0.1 billion	2013	Under construction
20.		The Fund - Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Under construction
21.		EEP - Cushing Terminal Storage Expansion Project	US$0.2 billion	US$0.1 billion	2012-2013 (in phases)	Under construction
22.		EEP - South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+ (in phases)	Under construction

	Project	Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
23.	EEP - Berthold Rail Project	US$0.1 billion	No significant expenditures to date	2013	Under construction
24.	EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.1 billion	2013	Under construction
25.	EEP - Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
26.	EEP - Texas Express Pipeline	US$0.4 billion	No significant expenditures to date	2013	Under construction
27.	EEP - Line 6B Replacement Program	US$0.3 billion	US$0.1 billion	2013	Under construction
28.	EEP - Eastern Access Expansion	US$2.2 billion	No significant expenditures to date	2013-2014 (in phases)	Pre-construction
29.	EEP - Lakehead System Mainline Expansion	US$0.4 billion	No significant expenditures to date	2014	Pre-construction
CORPORATE					
30.	Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2012-2014 (in stages)	Under construction

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

2 *Expenditures to date reflect total cumulative expenditures incurred from inception of project up to June 30, 2012.*

3 *See Growth Projects Sponsored Investments Enbridge Energy Partners, L.P Eastern Access Expansion for project discussion.*

LIQUIDS PIPELINES

Edmonton Terminal Expansion

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion, with expenditures to date of approximately $0.1 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge s Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of three booster pumps and related infrastructure. Regulatory approval was received in the first quarter of 2011 and the expansion is expected to be completed by December 2012.

Woodland Pipeline

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge s existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new Woodland Pipeline may be extended from Cheecham to Edmonton as part of future industry expansions. Regulatory approval for the Phase I facilities was received in June 2010 and construction is substantially complete. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, of which Enbridge s share is approximately $0.3 billion. Enbridge s share of total project expenditures to date is approximately $0.2 billion. Enbridge expects the pipeline will come into service in late 2012.

Wood Buffalo Pipeline

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor s oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to crude oil hubs in the Edmonton, Alberta area. The new Wood Buffalo Pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion, with expenditures to date of approximately $0.3 billion. Construction of the pipeline was substantially completed in the first quarter of 2012, with in service expected by late 2012 upon completion of the related station facilities.

Waupisoo Pipeline Capacity Expansion

The Waupisoo Pipeline Capacity Expansion, which received regulatory approval in November 2010, is expected to provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion.

Seaway Crude Pipeline System

Acquisition of Interest

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline system at a cost of approximately US$1.2 billion. The 1,078-kilometre (670-mile) Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma, 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 and four marine import facilities at two locations. The other 50% interest in the Seaway Pipeline system is owned by Enterprise Products Partners L.P. (Enterprise).

Reversal

In December 2011, Enbridge and Enterprise announced plans to reverse the flow direction of the Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the United States Gulf Coast. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into Enterprise s ECHO crude oil terminal (ECHO Terminal) southeast of Houston. The reversal of the pipeline and acceptance of first crude was completed in May 2012, providing initial capacity of 150,000 bpd. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd depending upon the mix of light and heavy grades of crude oil. Enbridge s expected cost for the reversal is approximately US$0.2 billion.

Expansion and Extension

In March 2012, Enbridge and Enterprise, based on additional capacity commitments from shippers, announced plans to proceed with an expansion of the Seaway Pipeline through construction of a second line that will more than double its capacity to 850,000 bpd by mid-2014. This 30-inch diameter pipeline, which will follow the same route, will twin the existing Seaway system.

In addition, a 137-kilometre (85-mile) pipeline will be constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region s heavy oil refining capabilities. This lateral will offer capacity of 560,000 bpd and, subject to regulatory approvals, is expected to be available in early 2014. Enbridge s investment to twin the pipeline and for the Port Arthur lateral is expected to be approximately US$1.0 billion.

South Cheecham Rail and Truck Terminal

The Company has partnered with Keyera Corp. to construct the South Cheecham Rail and Truck Terminal (the Terminal), located approximately 75 kilometres (47 miles) southeast of Fort McMurray, Alberta. The Terminal, to be developed in phases, will be a multi-purpose hydrocarbon rail and truck terminal, designed to support bitumen producers within the Athabasca oil sands area. In addition to the facilities for handling diluent and diluted bitumen at the Terminal, the initial phase is planned to include a diluted bitumen pipeline connection to Enbridge s existing Cheecham terminal. Completion of the first phase is expected to take place in the first half of 2013 for a total cost of approximately $90 million. Enbridge s share of the project costs will be based upon its 50% joint venture interest.

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company is undertaking construction of a new originating terminal (Norealis Terminal), a

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the

112-kilometre (66-mile) 24-inch diameter pipeline (Norealis 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 $0.1 billion. With regulatory approval received in the second quarter of 2011, the project is expected to be in service in late 2013.

Athabasca Pipeline Capacity Expansion

The Company is undertaking an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oilsands Project operated by Cenovus Energy. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion and an expected in-service date in the first quarter of 2013, for an initial 430,000 bpd of capacity. The balance of additional capacity is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Flanagan South Pipeline Project

The 950-kilometre (590-mile) Flanagan South Pipeline will have an initial capacity of 585,000 bpd to transport crude oil from the Company s terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline will be 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 by mid-2014. The estimated cost of the project is approximately US$2.8 billion. Both the Seaway and Flanagan South pipelines are included in the Company s Gulf Coast Access initiative to offer crude oil transportation from its terminal at Flanagan to the United States Gulf Coast.

Canadian Mainline Expansion

On May 16, 2012, Enbridge announced an estimated $0.2 billion expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The current scope of the project, which supports the Company s Gulf Coast Access initiative, will involve the addition of pumping horsepower sufficient to raise the capacity of the Canadian mainline by 120,000 bpd and is expected to be in service by mid-2014. The expansion remains subject to NEB approval.

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, will include 345 kilometres (210 miles) of 36-inch pipeline within the existing Athabasca Pipeline right-of-way. The initial annual capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory approvals, the line is expected to enter service in 2015.

Northern Gateway Project

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

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

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

In the fall of 2011, Northern Gateway responded to written questions by interveners and government participants.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the Panel would hear all oral evidence from registered interveners first, followed by oral statements from registered participants. Community hearings for oral evidence and statements took place between January and June 2012 in various communities. The JRP has now collected more than 90% of the oral evidence and 70% of the oral statements in locations which the proposed project passes. A written record of what was said each day in the community hearings is available on the Panel s website. Interveners responded to questions by Northern Gateway on July 6, 2012. Northern Gateway filed reply evidence to the evidence of the interveners on July 20, 2012. The Panel has scheduled final hearings commencing on September 4, 2012 through to December 2012 where Northern Gateway, interveners, government participants and the JRP will question those who have presented oral or written evidence.

Following the final hearings and prior to Final Argument, the Panel will hear additional oral statements from interested parties who do not reside along the pipeline corridor or shipping routes. Final Argument is proposed for March and April 2013. Based on this projected schedule, the JRP expects to issue its reports and findings on the proposed project by December 2013. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service in 2017 at the earliest. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.3 billion, of which approximately half is secured in funding from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

On February 23, 2012, Transport Canada published its TERMPOL Review Process Report of the Northern Gateway Project s proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: While there will always be residual risk in any project, after reviewing the proponent s studies and taking into account the proponent s commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway Project. The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

As noted above, Northern Gateway filed reply evidence with the JRP on July 20, 2012 which contained details of further enhancements in pipeline design and operations. These extra measures, estimated to cost an additional $400 million to $500 million, for a total estimated project cost of approximately $5.9 billion to $6.0 billion, include: increasing pipeline wall thickness of the oil pipeline; additional pipeline wall thickness for water crossings such as major tributaries to the Fraser, Skeen and Kitimat Rivers; increasing the number of remotely-operated isolation valves by 50% within British Columbia to protect high-value fish habitat; increasing frequency of in-line inspection surveys across the entire pipeline system by a minimum 50% over and above current standards; installing dual leak detection systems; and staffing pump stations in remote locations on a 24 hour / 7 day basis for on-site monitoring, heightened security and rapid response to abnormal conditions.

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Silver State North Solar Project

In March 2012, Enbridge acquired a 100% interest in the development of the 50-megawatt (MW) Silver State North Solar Project (Silver State), located 65 kilometres (40 miles) south of Las Vegas, Nevada. The project, which began commercial operation in May 2012, was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar is providing operations and maintenance services under a long-term contract. Energy output is being delivered to NV Energy, Inc.under a 25-year power purchase agreement (PPA). The Company s total investment in the project was approximately US$0.2 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. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1 is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year PPA and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company s total investment in the project is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.2 billion.

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 is expected to be approximately $1.1 billion, with expenditures to date of approximately $0.6 billion. Phase 1 of the development is to have 400 million cubic feet per day (mmcf/d) of processing capacity. The plant is currently under construction and is expected to be in service in late 2012. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. These producers can request the Company to expand Cabin up to an additional four phases, under agreed terms.

Tioga Lateral Pipeline

Alliance Pipeline US plans to develop a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. Through its 50% ownership interest in Alliance Pipeline US, Enbridge s expected cost related to the project is approximately US$0.1 billion. Alliance Pipeline US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products (Aux Sable) and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of high-energy, liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 106 mmcf/d, which can be expanded based on shipper demand. On January 25, 2012, Alliance Pipeline US filed an application for regulatory approval to construct and operate the Tioga Lateral and, pending approvals, the pipeline is expected to be in service by mid-2013.

Venice Condensate Stabilization Facility

The Company is carrying out an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. The expanded condensate processing capacity is required to accommodate additional natural gas production from the

Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge s onshore facility at Venice via Enbridge s Mississippi Canyon offshore pipeline system where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

Walker Ridge Gas Gathering System

The Company executed definitive agreements in 2010 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 will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day. WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.1 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge s plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion, and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to provide capacity of 145,000 bpd. The Bakken Expansion Program involves United States projects undertaken by EEP at a cost of approximately US$0.4 billion and Canadian projects undertaken by the Fund at a cost of approximately $0.2 billion. Regulatory approval has been received and construction commenced in July 2011 on the United States portion of the project, with expenditures to date of approximately US$0.1 billion. In Canada, NEB approval was secured in December 2011. Subject to other approvals in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013.

Enbridge Energy Partners, L.P.

Cushing Terminal Storage Expansion Project

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.4 million barrels. To date, nine tanks have been completed and placed into service, with the remaining four tanks expected to come into service by December 2012.

In July 2012, engineering design commenced on three new tanks and associated infrastructure totaling 770,000 barrels of incremental working capacity at EEP s Cushing Terminal, at an estimated cost of US$39 million, bringing the total estimated cost of the expansion to approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion. The expected in-service date for the three tanks is August 2013.

South Haynesville Shale Expansion

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, completed in the second quarter of 2012 at an approximate cost of US$0.1 billion, increased capacity of EEP s East Texas system by 900 mmcf/d.

EEP plans to invest an additional US$0.2 billion, with expenditures to date of approximately US$0.1 billion, to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. Due to lower levels of producer activity, in light of weak gas prices, EEP has deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Berthold Rail Project

EEP is proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project is expected to expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing infrastructure, with an expected in-service date by early 2013.

Ajax Cryogenic Processing Plant

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion, with expenditures to date of approximately US$0.1 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. When operational, the Ajax Plant in conjunction with the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

Bakken Access Program

The Bakken Access Program, a series of projects totaling approximately US$0.1 billion, represents an upstream expansion that will further complement EEP s Bakken expansion. This expansion program will enhance gathering capabilities on the North Dakota System by 100,000 bpd. The program, which involves increasing pipeline capacities, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

Texas Express Pipeline

The Texas Express Pipeline (TEP) is a joint venture with Enterprise, Anadarko Petroleum Corporation and DCP Midstream LLC to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the TEP, which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline.

One of the new NGL gathering systems will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, while the second will connect TEP to central Texas Barnett Shale processing plants. Subject to regulatory approvals and finalization of commercial terms, the pipeline and portions of the gathering systems are expected to begin service in mid-2013.

Line 6B 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 targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP s tariff surcharge that is part of the system-wide rates of the Lakehead System. The total capital for this replacement program is estimated to be US$0.3 billion, with expenditures to date of approximately US$0.1 billion.

Eastern Access Expansion

As previously announced in 2011, Enbridge and EEP will undertake two projects to provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. One project involves the expansion of EEP s Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. Complementing the Line 5 expansion, Enbridge plans to reverse a portion of its Line 9 (Line 9A) in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million. Subject to regulatory approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013. In July 2012, the NEB approved the Line 9A reversal which is expected to be in service in late 2013.

On May 16, 2012, Enbridge announced that it had secured commercial support to proceed with additional Eastern Access projects. Enbridge and EEP also expect to proceed with supporting expansions of the United States mainline system between Flanagan, Illinois and Sarnia, Ontario. The additional Eastern Access projects include an 80,000 bpd expansion of Enbridge s Toledo Pipeline (Line 17), which connects with the Enbridge mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan, and a reversal of Enbridge s 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec. Sufficient capacity has been requested by refineries seeking to secure access to ample crude oil supplies from western Canada and the Bakken region in North Dakota to warrant proceeding with the project. The Eastern Access Line 9B reversal remains subject to NEB regulatory approval.

The Toledo Pipeline expansion is expected to be available for service in early 2013 at a cost of approximately US$0.2 billion. The Line 9B reversal is expected to be available for service in early 2014 at a cost of approximately $0.3 billion. Both the Toledo Pipeline and Line 9 assets are included in the Company s Liquids Pipelines segment.

The supporting mainline expansions include expansion of the Spearhead North pipeline (Line 62) between Flanagan and Griffith, Indiana, an additional 330,000 barrel tank at Griffith and the replacement of additional sections of Line 6B in Indiana and Michigan not already scheduled for replacement as previously announced. The capacity of Spearhead North will increase by 105,000 bpd and the capacity of Line 6B will increase by 260,000 bpd. The expected cost of the mainline expansions is US$2.2 billion, including the US$0.1 billion cost of the previously announced Line 5 expansion. In addition, the supporting mainline expansions will be funded 60% by Enbridge and 40% by EEP, with EEP having the option to reduce its funding and associated economic interest in the projects by up to 15% before the end of 2012. Furthermore, within one year of the in-service date, scheduled for early 2014, EEP will also have the option to increase its economic interest held at that time by up to 15%.

Lakehead System Mainline Expansion

On May 16, 2012, EEP announced 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. The current scope of the projects includes expansion of the Alberta Clipper line between the border and Superior, Wisconsin from 450,000 bpd to 570,000 bpd, and expansion of the Southern Access line between Superior and Flanagan, Illinois from 400,000 bpd to 560,000 bpd. The projects require only the addition of pumping horsepower, with no line pipe construction. Alberta Clipper and Southern Access are both held in Enbridge Energy, Limited Partnership (EELP), which will be fully funded by EEP for the cost of the expansions. The scope of the expansions remains under discussion, which could lead to an upward revision to capacity and cost.

Subject to finalization of scope, the expansions will be undertaken by EELP on a full cost-of-service basis, and are expected to be available for service in mid-2014 at an estimated cost of US$0.4 billion. The expansions are designed to accommodate increased throughput on the Lakehead System for deliveries to Enbridge s Gulf Coast Access initiative, as well as growth in Chicago area refinery requirements. These expansions are incremental to those undertaken as part of the Eastern Access expansion.

Athabasca Pipeline Capacity Expansion

CORPORATE

Montana-Alberta Tie-Line

Montana-Alberta Tie-Line (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

16

Montana and buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 250-MW to 300-MW has been increased to approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. While the permits required for construction have been obtained, the Alberta Utility Commission s approval in Canada is currently being updated to reflect a number of design modifications and on-going consultation with land owners. Subject to this approval, the system s north-bound capacity, which is fully contracted, is expected to be in service in the fourth quarter of 2012, with the expansion expected to be completed by the end of 2014.

Neal Hot Springs Geothermal Project

The Company has partnered with U.S. Geothermal Inc. (U.S. Geothermal) to develop the 35-MW (22-MW, net) Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. Completion of the project has been extended to the end of 2012 and, once operational, the facility will deliver electricity to the Idaho Power grid under a 25-year PPA. Enbridge will invest up to approximately US$33 million for a 41% interest in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Canadian Mainline	**96**	81	**195**	163
Regional Oil Sands System	**23**	26	**50**	53
Southern Lights Pipeline	**20**	17	**37**	36
Spearhead Pipeline	**11**	-	**22**	10
Feeder Pipelines and Other	**2**	-	**6**	(2)
Adjusted earnings	**152**	124	**310**	260
Canadian Mainline - shipper dispute settlement	**-**	14	**-**	14
Canadian Mainline - Line 9 tolling adjustment	**-**	13	**6**	13
Canadian Mainline - unrealized derivative fair value gains/(loss)	**(34)**	46	**(7)**	46
Spearhead Pipeline - unrealized derivative fair value gains	**1**	-	**1**	-
Earnings	**119**	197	**310**	333

Canadian Mainline earnings for the first six months of 2012 were governed by the CTS (with the exception of Lines 8 and 9), whereas earnings for the first six months of 2011 were governed by a series of agreements, the most significant being the Incentive Tolling Settlement applicable to the mainline system and the Terrace and Alberta Clipper agreements. Earnings under the CTS are subject to variability in throughput volume and operating costs. Canadian Mainline volumes during the first half of 2012 were higher than expected contributing to an increase in earnings relative to the prior year, partially offset by higher operating and administrative costs, primarily due to higher employee related costs, higher leak repairs and the timing of integrity work. Incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota have bolstered supply to midwest markets, and placed increased downward pressure on crude oil prices in the midwest, pending completion of Enbridge s market access projects. This discounted crude oil, coupled with strong refining margins, is increasing demand in the midwest for Canadian and Bakken crude oil supply and driving increased long haul barrels on Canadian Mainline and EEP s Lakehead System.

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

	Three months ended June 30, 2012	Six month ended June 30, 2012
(millions of Canadian dollars, unless otherwise noted)		
Revenues	**340**	**656**
Expenses		
Operating and administrative	**109**	**190**
Power	**26**	**55**
Depreciation and amortization	**55**	**109**
	190	**354**
	150	**302**
Other expense	**-**	**(3)**
Interest expense	**(34)**	**(65)**
	116	**234**
Income taxes	**(20)**	**(39)**
Adjusted earnings	**96**	**195**
Effective United States dollar to Canadian dollar exchange rate[1]	**0.975**	**0.967**

During the three months ended June 30, 2012, the following tolls were in effect:	
International Joint Tariff (IJT) Benchmark Toll[2] *(United States dollars per barrel)*	**$3.85**
Lakehead System Local Toll[3] *(United States dollars per barrel)*	**$1.76**
Canadian Mainline IJT Residual Benchmark Toll[4] *(United States dollars per barrel)*	**$2.09**

1 *Inclusive of realized gains or losses on foreign exchange derivative financial instruments.*
2 *The 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, 2012, the IJT benchmark toll increased to US$3.94.*
3 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2012, this toll decreased from US$2.01 to US$1.76 and, effective July 1, 2012, it increased to US$1.85.*
4 *The Canadian Mainline IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. Effective April 1, 2012, this toll increased from US$1.84 to US$2.09, with no change effective July 1, 2012. For any shipment this toll is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.*

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,659**	1,459	**1,673**	1,532

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

Canadian Mainline revenues included the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Line 8 and Line 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 Canadian Local Toll (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 may utilize 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 expenses 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 and tax rates, the addition of new facilities and more extensive integrity and maintenance programs.

Power is the most significant variable operating cost and is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements. However, the primary determinants of power cost are the level of 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 may utilize derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and additions to property, plant and equipment due to new facilities, as well as maintenance and 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, revenue on the Canadian Mainline was 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. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods is being recovered through a surcharge to the CLT and IJT. While the CTS is based on previous tolling settlements and cost-of-service principles, earnings are subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of deferred income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to deferred income taxes will continue to be recognized as incurred.

Regional Oil Sands System earnings for the first six months of 2012 decreased primarily as a result of higher operating and administrative expenses partially offset by higher shipped volumes and increased tolls on the Athabasca Pipeline.

Spearhead Pipeline adjusted earnings increased as a result of higher volumes and tolls, as well as the recognition of expired shipper make-up rights compared with prior year. Volumes significantly increased over 2011 due to increased demand at Cushing, Oklahoma in anticipation of additional capacity on the Seaway Pipeline for further transportation to the United States Gulf Coast.

Athabasca Pipeline Capacity Expansion

The earnings increase in Feeder Pipelines and Other, which includes the Seaway Pipeline, primarily reflected a higher contribution from Olympic Pipeline resulting from a tariff increase, as well as higher volumes on Toledo Pipeline. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP s Lakehead System.

Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items.

- Canadian Mainline earnings for 2011 included $14 million from the settlement of a shipper dispute related to oil measurement adjustments in prior years.

- Canadian Mainline earnings included a Line 9 tolling adjustment related to services provided in prior periods.

- Canadian Mainline earnings reflected unrealized fair value gains and losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.

- Spearhead Pipeline earnings included unrealized fair value gains on derivative financial instruments used to manage exposures to allowance oil commodity prices.

GAS DISTRIBUTION

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
(millions of Canadian dollars)				
Enbridge Gas Distribution (EGD)	**29**	29	**110**	107
Other Gas Distribution and Storage	**-**	9	**21**	22
Adjusted earnings	**29**	38	**131**	129
EGD - colder/(warmer) than normal weather	**-**	2	**(24)**	13
EGD - tax rate changes	**(9)**	-	**(9)**	-
Earnings	**20**	40	**98**	142

The increase in EGD s adjusted earnings for the six months ended June 30, 2012 was primarily due to customer growth and lower interest expense, partially offset by higher system integrity and operating and administrative costs as well as higher depreciation expense. In addition, compared with the prior year, lower per unit volumetric charges with corresponding increases in fixed charges are expected to modify EGD s quarterly earnings profile, but not materially impact full year earnings as earnings are shifted from the colder winter months to the warmer summer months.

The change in earnings from Other Gas Distribution and Storage was primarily due to the discontinuance of rate regulated accounting for EGNB in the first quarter of 2012. This discontinuance will result in earnings being subject to increased variability, including quarterly seasonality, as there will be no further accumulation of the regulatory deferral account. Earnings will increase in the colder winter months when demand for natural gas is high and earnings will decrease in the warmer summer months when demand, and therefore delivered volumes, is low. As a result of recent amendments to the rate setting methodology to which EGNB is subject, on a full year basis earnings are expected to be approximately 60% lower than the $20 million earned in 2011. See *Recent Developments Gas Distribution Enbridge Gas New Brunswick Regulatory Matters.*

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting item.

- EGD earnings are adjusted to reflect the impact of weather.

- In 2012, earnings from EGD reflected the impact of unfavourable tax rate changes.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Enbridge Offshore Pipelines (Offshore)	**(2)**	(3)	**1**	(1)
Alliance Pipeline US	**6**	6	**12**	13
Vector Pipeline	**3**	4	**8**	9
Aux Sable	**14**	13	**26**	24
Energy Services	**18**	16	**22**	25
Other	**6**	6	**12**	11
Adjusted earnings	**45**	42	**81**	81
Aux Sable - unrealized derivative fair value gains/(loss)	**16**	(1)	**23**	(7)
Energy Services - unrealized derivative fair value gains/(loss)	**(172)**	36	**(326)**	29
Other - unrealized derivative fair value loss	**(3)**	-	**(3)**	-
Earnings/(loss)	**(114)**	77	**(225)**	103

Offshore adjusted earnings for the six months ended June 30, 2012 included a higher transportation rate for volumes shipped on the Stingray Pipeline System, as well as a $2 million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011. Overall, Offshore is expected to be in a loss position for the full year as the Company continues to experience weak volumes due to delayed drilling programs and more scheduled production outages by producers in the Gulf of Mexico.

Aux Sable adjusted earnings increased primarily as a result of contributions from new assets acquired in July 2011, including Prairie Rose Pipeline and the Palermo Conditioning Plant.

Energy Services operates a physical commodity marketing business which captures quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines. Energy Services adjusted earnings for the six months ended June 30, 2012 declined due to changing market conditions which gave rise to fewer margin opportunities in liquids marketing. Adjusted earnings for the three months ended June 30, 2012 increased as a result of stronger margins in oil marketing.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items.

- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company s forward gas processing risk management position.

- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of forward transportation and storage transactions. 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 will be realized in the future when the physical transaction settles. Unlike the change in the value of the financial derivative, the loss or gain on the value of the underlying physical transaction is not recorded for financial statement purposes until the periods in which it is realized.

- Other earnings for 2012 reflected unrealized fair value changes on derivative financial instruments.

21

SPONSORED INVESTMENTS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Enbridge Energy Partners (EEP)	**32**	34	**68**	65
Enbridge Energy, Limited Partnership - Alberta Clipper US (EELP)	**12**	10	**22**	22
Enbridge Income Fund (the Fund)	**16**	12	**37**	22
Adjusted earnings	**60**	56	**127**	109
EEP - NGL trucking and marketing investigation costs	**-**	-	**(1)**	-
EEP - unrealized derivative fair value gains	**7**	3	**7**	-
EEP - leak insurance recoveries	**-**	3	**-**	8
EEP - leak remediation costs	**(2)**	(6)	**(2)**	(6)
EEP - shipper dispute settlement	**-**	8	**-**	8
EEP - lawsuit settlement	**-**	-	**-**	1
EEP - impact of unusual weather conditions	**-**	-	**-**	(1)
Earnings	**65**	64	**131**	119

EEP adjusted earnings for 2012 included higher incentive income and strong results from the liquids business primarily due to higher average daily delivery volumes on all major liquids systems, as well as an increased contribution from storage terminal facilities that were placed into service during 2012. Earnings from the natural gas business decreased as a result of significantly lower NGL prices. An increase in operating and administrative costs, primarily workforce-related costs, as well as higher interest expense also impacted EEP s 2012 adjusted earnings.

Earnings for the Fund for 2012 included earnings from the Ontario Wind, Sarnia Solar and Talbot Wind energy projects (the Renewable Assets) acquired from a wholly-owned subsidiary of Enbridge in October 2011. Prior to October 2011, earnings from the Renewable Assets were presented within the Gas Pipelines, Processing and Energy Services segment. Partially offsetting strong contributions from the Renewable Assets were increased interest costs associated with funding the acquisition as well as higher deferred income taxes.

Sponsored Investment earnings were impacted by the following non-recurring or non-operating adjusting items.

- EEP earnings for 2012 reflected a charge for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.

- Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.

- Earnings from EEP for 2011 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Line 6A and 6B Crude Oil Releases.*

- Earnings from EEP for each period included a charge related to estimated costs, before insurance recoveries, associated with the Line 6A and 6B crude oil releases. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Line 6A and 6B Crude Oil Releases.*

- EEP earnings for 2011 included proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years.

- EEP earnings 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.

CORPORATE

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Noverco	**2**	3	**22**	17
Other Corporate	**(11)**	(5)	**(18)**	(8)
Adjusted earnings/(loss)	**(9)**	(2)	**4**	9
Noverco - equity earnings adjustment	**-**	-	**(12)**	-
Other Corporate - unrealized derivative fair value loss	**(67)**	(65)	**(57)**	(49)
Other Corporate - foreign tax recovery	**-**	-	**29**	-
Other Corporate - unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**-**	(1)	**-**	17
Other Corporate - impact of tax rate changes	**(3)**	(8)	**(3)**	(8)
Loss	**(79)**	(76)	**(39)**	(31)

Noverco adjusted earnings for the six months ended June 30, 2012 reflected contributions from the Company s increased preferred share investment.

The increase in Other Corporate adjusted loss was primarily due to an increase in net Corporate segment financing costs, inclusive of preference share dividends. Since July 2011, the Company issued an additional 114 million preference shares for gross proceeds of approximately $2,860 million. See *Recent Developments Corporate Preference Share Issuances.*

Corporate costs were impacted by the following non-recurring or non-operating adjusting items.

- Earnings from Noverco for the six months ended June 30, 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Earnings for each period included a change in the unrealized fair value losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Earnings for 2012 were impacted by taxes related to a historical foreign investment.
- Earnings for 2011 included net unrealized foreign exchange gains and losses on the translation of foreign-denominated intercompany balances.
- Earnings/(loss) for 2011 were impacted by tax rate changes.

LIQUIDITY AND CAPITAL RESOURCES

The Company 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 has also been active in the equity markets in the first six months of 2012 to further bolster liquidity in support of the Company s suite of growth projects, placing approximately $610 million in preference shares, with a subsequent issue in July raising an additional $450 million. During the second quarter of 2012, the Company was also successful in issuing 9.83 million common shares for gross proceeds of approximately $400 million. Further, in July 2012, the Company s subsidiary Enbridge Pipelines Inc. (EPI) issued a $100 million Century Bond with a 100-year term to maturity. EEP was also successful in securing a new US$675 million credit facility.

At June 30, 2012, excluding the Southern Lights project financing, the Company had $11,090 million of committed credit facilities of which $2,737 million were either drawn or allocated to backstop commercial paper. Inclusive of cash and cash equivalents, net of bank indebtedness, of $340 million, the Company had net available liquidity of $8,693 million at June 30, 2012. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company s credit facilities at June 30, 2012.

	Maturity Dates1	Total Facilities	Credit Facility Draws2	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012-2013	**712**	**224**	**488**
Sponsored Investments3	2015-2016	**2,538**	**1,104**	**1,434**
Corporate	2013-2016	**7,540**	**1,383**	**6,157**
		11,090	**2,737**	**8,353**
Southern Lights project financing4	2013-2014	**1,520**	**1,450**	**70**
Total credit facilities		**12,610**	**4,187**	**8,423**

1 *Total facilities include $30 million in demand facilities with no maturity date.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *In July 2012, the Company secured a new US$675 million 364-day facility*
4 *Total facilities inclusive of $61 million for debt service reserve letters of credit.*

OPERATING ACTIVITIES

Cash provided by operating activities was $984 million and $1,632 million for the three and six months ended June 30, 2012 respectively, compared with $696 million and $1,859 million for the three and six months ended June 30, 2011. Cash provided by operating activities for both the three and six months ended June 30, 2012 included a $317 million one-time dividend received on the Company s investment in Noverco. In the first quarter of 2012, Noverco realized a substantial gain on the disposition of a portion of its investment in Enbridge shares and subsequently distributed the proceeds from this transaction to its shareholders, by way of dividend, on May 18, 2012. The one-time Noverco dividend and the Company s growing cash flows from development projects placed into service in recent years, from the favourable operating performance of Canadian Mainline under CTS and from increased contributions from Sponsored Investments, was offset by variations in working capital accounts in the first six months of 2012. Changes in operating assets and liabilities contributed $691 million to the overall net decline in cash provided by operating activities for the first half of 2012 compared with the first half of 2011. Working capital will fluctuate from time to time due to natural gas inventory and borrowing levels at EGD, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company s Energy Services businesses, among others. Other changes in operating assets and liabilities in 2012 included receipt of insurance payments for claims made in conjunction with the Line 6B crude oil release, collecting some of the cash outlays incurred in 2011.

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 $21 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three and six months ended June 30, 2012 was $1,475 million and $2,403 respectively, compared with $839 million and $1,486 million for the three and six months ended June 30, 2011. Cash used in investing activities included $2,059 million (2011 - $1,131 million) of additions to property, plant and equipment during the first half of 2012, primarily directed to the Company s growth projects, partially offset by the timing of cash payments of construction payables. The increase in cash used in investing activities was also attributable to greater intangible asset additions, primarily software, and additional funding of various investments and joint ventures, namely the Texas Express and Woodland Pipelines.

24

Investing activities for the second quarter of 2012 also included the acquisition of the remaining 10% of Greenwich as well as payment of the balance of the purchase price owing on the Silver State acquisition that was completed in the first quarter of 2012.

FINANCING ACTIVITIES

Cash generated from financing activities was $721 million for the six months ended June 30, 2012 compared with cash used in financing activities of $171 million in the corresponding period of 2011. For the three months ended June 30, 2012, cash generated was $58 million (2011 - $130 million). The increase in cash provided by financing activities for the first six months of 2012 was primarily due to issuances of both preference shares and debenture and term notes of $1,418 million and $500 million, respectively. In addition, the Company completed a common equity issuance on June 8, 2012, for gross proceeds of approximately $400 million. The Company accesses capital markets as required to finance currently secured capital projects and to provide flexibility for new growth opportunities. These increases were partially offset by higher net repayments of bank indebtedness and short-term borrowings and commercial paper and credit facility draws. Additionally, cash used in financing activities for the first half of 2012 included routine distributions to third party investors in EEP and the Fund of $202 million (2011 - $84 million) and $23 million (2011 - $14 million), respectively.

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2012, dividends declared were $217 million (2011 - $190 million), of which $145 million (2011 - $136 million) were paid in cash and reflected in financing activities. The remaining $72 million (2011 - $54 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 six months ended June 30, 2012, dividends declared were $438 million (2011 - $378 million), of which $301 million (2011 - $260 million) were paid in cash and reflected in financing activities. The remaining $137 million (2011 - $118 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and six months ended June 30, 2012, 33% (2011 - 28%) and 31% (2011 - 31%) of total dividends declared were reinvested.

On August 1, 2012, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2012 to shareholders of record on August 15, 2012.

Common Shares	$0.28250
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[1]	$0.42470
Preference Shares, Series J[2]	US$0.36990
Preference Shares, Series L[3]	US$0.27670

1 *This first dividend declared for the Preference Shares, Series H includes accrued dividends from March 29, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on December 1, 2012.* See *Recent Developments Corporate Preference Share Issuances.*

2 *This first dividend declared for the Preference Shares, Series J includes accrued dividends from April 19, 2012, the date the shares were issued. The regular quarterly dividend of US$0.25 per share will take effect on December 1, 2012.* See *Recent Developments Corporate Preference Share Issuances.*

3 *This first dividend declared for the Preference Shares, Series L includes accrued dividends from May 23, 2012, the date the shares were issued. The regular quarterly dividend of US$0.25 per share will take effect on December 1, 2012.* See *Recent Developments Corporate Preference Share Issuances.*

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,167 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

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

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

Foreign Exchange Risk

The Company s earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. 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 volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 2.08%.

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 2016. A total of $10,640 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.50%.

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 band 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, power, crude oil 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.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGL) that impact earnings from its ownership in the Aux Sable natural gas processing plant and the gathering and processing business held by EEP.

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 cash flow hedges and net investment hedges on the Company s consolidated earnings and consolidated comprehensive income.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(10)**	(23)	**9**	(42)
Interest rate contracts	**(369)**	(63)	**(189)**	15
Commodity contracts	**89**	61	**81**	5
Other contracts	**1**	1	**-**	2
Net investment hedges				
Foreign exchange contracts	**(21)**	5	**(18)**	25
	(310)	(19)	**(117)**	5
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Cash flow hedges				
Foreign exchange contracts[1]	**(1)**	-	**(1)**	-
Interest rate contracts[2]	**10**	5	**24**	9
Commodity contracts[3]	**(5)**	(21)	**(3)**	(30)
Other contracts	**-**	(1)	**-**	(1)
	4	(17)	**20**	(22)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Cash flow hedges				
Interest rate contracts[2]	**4**	(9)	**4**	(9)
Commodity contracts[3]	**(3)**	-	**(5)**	1
	1	(9)	**(1)**	(8)
Non-qualifying derivatives				
Foreign exchange contracts[1]	**(76)**	(20)	**(61)**	2
Interest rate contracts[2]	**1**	4	**(1)**	4
Commodity contracts[4]	**(239)**	87	**(442)**	53
Other contracts[5]	**5**	2	**5**	-
Total unrealized derivative fair value loss	**(309)**	73	**(499)**	59

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

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at June 30, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

The Company generally has a policy of entering into International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our 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 counterparites 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. 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, 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 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.

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued several 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 NEB, the Company filed its estimates of abandonment costs for its regulated pipeline systems within EPI and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc. and Vector Pipelines Limited Partnership (Group 2 companies). The NEB is also requiring regulated pipeline companies to file a proposed process for collecting and setting aside the funds for future abandonment costs by November 30, 2012 for Group 1 companies and by March 31, 2013 for Group 2 companies. These costs would be recovered from shippers through tolls in accordance with NEB s determination that abandonment costs are a legitimate cost of providing services and are recoverable upon NEB approval from users of the system.

Both of the required submissions will require NEB approval and will result in increased transportation tolls and regulatory liabilities. The specific toll impacts are uncertain at this time as they will be the subject of NEB filings in late 2012 and early 2013.

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

CHANGE 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 an SEC registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

To facilitate users understanding of the transition to U.S. GAAP, the Company restated its 2011 consolidated financial statements, which were originally prepared in accordance with Part V, to U.S. GAAP, including full comparative information and related note disclosure. The 2011 U.S. GAAP financial statements were filed with securities regulators in Canada and the United States on May 2, 2012 and are available on SEDAR at www.sedar.com and on the Company s website at www.enbridge.com. None of the information contained on, or connected to, Enbridge s website is incorporated or otherwise part of this MD&A.

Fair Value Measurement

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board s joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company s presentation of comprehensive income and did not impact the Company s consolidated financial statements.

Goodwill Impairment

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

QUARTERLY FINANCIAL INFORMATION

	2012[1]		2011[1]				2010[2]	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(millions of Canadian dollars, except per share amounts)								
Revenues	**5,718**	6,627	7,237	6,277	6,938	6,529	4,193	3,493
Earnings attributable to common shareholders	**11**	264	159	(5)	302	364	326	157
Earnings per common share[3]	**0.01**	0.35	0.21	(0.01)	0.40	0.49	0.44	0.21
Diluted earnings per common share[3]	**0.01**	0.34	0.21	(0.01)	0.40	0.48	0.43	0.21
Dividends per common share[3]	**0.2825**	0.2825	0.2450	0.2450	0.2450	0.2450	0.2125	0.2125
EGD - warmer/(colder) than normal weather	**-**	24	12	-	(2)	(11)	(6)	-
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**252**	110	(251)	251	(17)	(18)	(71)	(45)

1 Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.
2 Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.
3 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

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, unrealized fair value gains and losses on these instruments will impact earnings. The revaluation of foreign-denominated intercompany loans also impacts earnings each quarter.

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*.

In addition to the impacts of weather in EGD s franchise area and unrealized gains and losses outlined above, the following significant items impacted the Company s quarterly earnings.

- Reflected in earnings is the Company s share of leak remediation costs and lost revenue associated with the Line 6A and Line 6B crude oil releases. For the first and second quarters of 2012, these amounts were $nil and $2 million (2011 - $5 million and $6 million), respectively. Amounts of $21 million and $6 million (2010 - $85 million and $21 million) were recognized in the third and fourth quarters of 2011, respectively. Earnings for 2011 also reflected insurance recoveries associated with the Line 6B crude oil release of $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters, respectively.

- Earnings for the fourth quarter of 2011 included a charge totaling $262 million, after-tax, as a result of the discontinuance of rate regulated accounting at EGNB. This item was recognized as an extraordinary item in the Company s 2011 U.S. GAAP consolidated financial statements.

- First quarter 2011 earnings reflected positive contributions from gas gathering assets purchased in the fourth quarter of 2010.

- In April and July of 2010, the Company completed Alberta Clipper and Southern Lights Pipeline, respectively, two of the largest projects in the Company s history, and commenced recording in-service earnings from their respective completion dates forward.

NON-GAAP RECONCILIATION

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
GAAP earnings as reported	**11**	302	**275**	666
Significant after-tax non-recurring or non-operating factors and variances:				
Liquids Pipelines				
Canadian Mainline - shipper dispute settlement	**-**	(14)	**-**	(14)
Canadian Mainline - Line 9 tolling adjustment	**-**	(13)	**(6)**	(13)
Canadian Mainline - unrealized derivative fair value (gains)/loss	**34**	(46)	**7**	(46)
Spearhead Pipeline - unrealized derivative fair value gains	**(1)**	-	**(1)**	-
Gas Distribution				
EGD - (colder)/warmer than normal weather	**-**	(2)	**24**	(13)
EGD - tax rate changes	**9**	-	**9**	-
Gas Pipelines, Processing and Energy Services				
Aux Sable - unrealized derivative fair value (gains)/loss	**(16)**	1	**(23)**	7
Energy Services - unrealized derivative fair value (gains)/loss	**172**	(36)	**326**	(29)
Other - unrealized derivative fair value loss	**3**	-	**3**	-
Sponsored Investments				
EEP - NGL trucking and marketing investigation costs	**-**	-	**1**	-
EEP - unrealized derivative fair value gains	**(7)**	(3)	**(7)**	-
EEP - leak insurance recoveries	**-**	(3)	**-**	(8)
EEP - leak remediation costs	**2**	6	**2**	6
EEP - shipper dispute settlement	**-**	(8)	**-**	(8)
EEP - lawsuit settlement	**-**	-	**-**	(1)
EEP - impact of unusual weather conditions	**-**	-	**-**	1
Corporate				
Noverco - equity earnings adjustment	**-**	-	**12**	-
Other Corporate - unrealized derivative fair value loss	**67**	65	**57**	49
Other Corporate - foreign tax recovery	**-**	-	**(29)**	-
Other Corporate - unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**-**	1	**-**	(17)
Other Corporate - impact of tax rate changes	**3**	8	**3**	8
Adjusted earnings	**277**	258	**653**	588

32

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
Common Shares - issued and outstanding (voting equity shares)	797,142,746
Stock Options - issued and outstanding (20,287,864 vested)	34,841,384

1 *Outstanding share data information is provided as at July 23, 2012.*
2 *All preference shares are non-voting equity shares. Series A Preference Shares 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.*

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

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

June 30, 2012

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**4,504**	5,520	**9,342**	10,257
Gas distribution sales	**328**	355	**1,095**	1,108
Transportation and other services	**886**	1,063	**1,908**	2,102
	5,718	6,938	**12,345**	13,467
Expenses				
Commodity costs	**4,302**	5,285	**8,963**	9,876
Gas distribution costs	**141**	184	**700**	739
Operating and administrative	**681**	478	**1,313**	986
Depreciation and amortization	**300**	274	**590**	551
Environmental costs, net of recoveries	**23**	22	**26**	(11)
	5,447	6,243	**11,592**	12,141
	271	695	**753**	1,326
Income from equity investments	**34**	54	**72**	109
Other income/(expense)	**(31)**	31	**55**	111
Interest expense	**(213)**	(236)	**(430)**	(466)
	61	544	**450**	1,080
Income taxes recovery/(expense) *(Note 10)*	**18**	(144)	**(12)**	(247)
Earnings	**79**	400	**438**	833
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(45)**	(96)	**(125)**	(163)
Earnings attributable to Enbridge Inc.	**34**	304	**313**	670
Preference share dividends	**(23)**	(2)	**(38)**	(4)
Earnings attributable to Enbridge Inc. common shareholders	**11**	302	**275**	666
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.01**	0.40	**0.36**	0.89
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.01**	0.40	**0.35**	0.88

See accompanying notes to the unaudited consolidated financial statements.

2

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars)				
Earnings	**79**	400	**438**	833
Other comprehensive income/(loss)				
Change in unrealized gain/(loss) on cash flow hedges, net of tax	**(288)**	(14)	**(128)**	16
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(27)**	10	**(18)**	40
Reclassification to earnings/(loss) of realized cash flow hedges, net of tax	**6**	7	**19**	(7)
Reclassification to earnings of unrealized cash flow hedges, net of tax	**(3)**	(8)	**(1)**	(8)
Other comprehensive income/(loss) from equity investees, net of tax	**4**	(1)	**(1)**	(5)
Reclassification to earnings of gain from pension plans, net of tax	**1**	2	**7**	6
Change in foreign currency translation adjustment	**163**	(50)	**35**	(219)
Other comprehensive loss	**(144)**	(54)	**(87)**	(177)
Comprehensive income/(loss)	**(65)**	346	**351**	656
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(71)**	(77)	**(127)**	(57)
Comprehensive income/(loss) attributable to Enbridge Inc.	**(136)**	269	**224**	599
Preference share dividends	**(23)**	(2)	**(38)**	(4)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(159)**	267	**186**	595

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Six months ended June 30,	
	2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 6)*		
Balance at beginning of period	**1,056**	125
Shares issued	**1,428**	-
Balance at end of period	**2,484**	125
Common shares *(Note 6)*		
Balance at beginning of period	**3,969**	3,683
Shares issued	**388**	-
Dividend reinvestment and share purchase plan	**138**	118
Shares issued on exercise of stock options	**35**	26
Balance at end of period	**4,530**	3,827
Additional paid-in capital		
Balance at beginning of period	**242**	131
Stock-based compensation	**17**	12
Options exercised	**(6)**	(3)
Dilution gains and other	**(20)**	(3)
Issuance of treasury stock *(Note 8)*	**236**	-
Balance at end of period	**469**	137
Retained earnings		
Balance at beginning of period	**3,926**	3,993
Earnings attributable to Enbridge Inc.	**313**	670
Preference share dividends	**(38)**	(4)
Common share dividends declared	**(438)**	(378)
Dividends paid to reciprocal shareholder	**5**	12
Redemption value adjustment attributable to redeemable noncontrolling interests	**(79)**	(29)
Balance at end of period	**3,689**	4,264
Accumulated other comprehensive loss *(Note 7)*		
Balance at beginning of period	**(1,532)**	(1,027)
Other comprehensive loss attributable to Enbridge Inc. common shareholders	**(89)**	(72)
Balance at end of period	**(1,621)**	(1,099)
Reciprocal shareholding		
Balance at beginning of period	**(187)**	(154)
Issuance of treasury stock *(Note 8)*	**61**	-
Acquisition of equity investment	**-**	(33)
Balance at end of period	**(126)**	(187)
Total Enbridge Inc. shareholders equity	**9,425**	7,067
Noncontrolling interests		
Balance at beginning of period	**3,141**	2,424
Earnings attributable to noncontrolling interests	**124**	164
Other comprehensive income/(loss) attributable to noncontrolling interests		
Change in realized and unrealized gains/(loss) on cash flow hedges, net of tax	**1**	(39)
Change in foreign currency translation adjustment	**4**	(67)
	5	(106)
Comprehensive income attributable to noncontrolling interests	**129**	58
Contributions	**3**	86
Distributions	**(205)**	(169)
Acquisitions	**(25)**	(27)
Other	**(4)**	(16)
Balance at end of period	**3,039**	2,356
Total equity	**12,464**	9,423
Dividends paid per common share	**0.565**	0.490

See accompanying notes to the unaudited consolidated financial statements.

4

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**79**	400	**438**	833
Depreciation and amortization	**300**	274	**590**	551
Unrealized (gains)/loss on derivative instruments	**330**	(61)	**531**	(45)
Cash distributions in excess of equity earnings	**346**	36	**404**	56
Deferred income taxes (recovery)/expense	**(61)**	73	**(84)**	151
Other	**27**	22	**47**	18
Change in regulatory assets and liabilities	**8**	(7)	**22**	24
Change in environmental liabilities, net of recoveries	**(7)**	6	**(9)**	(113)
Change in operating assets and liabilities	**(38)**	(47)	**(307)**	384
	984	696	**1,632**	1,859
Investing activities				
Additions to property, plant and equipment	**(1,182)**	(595)	**(2,059)**	(1,131)
Additions to intangible assets	**(36)**	(10)	**(84)**	(19)
Change in construction payable	**43**	(44)	**114**	(118)
Long-term investments	**(82)**	(169)	**(145)**	(190)
Affiliate loans, net	**1**	1	**3**	3
Acquisition *(Note 4)*	**(214)**	(28)	**(221)**	(28)
Change in restricted cash	**(5)**	6	**(11)**	(3)
	(1,475)	(839)	**(2,403)**	(1,486)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**66**	130	**(106)**	(4)
Net change in commercial paper and credit facility draws	**(697)**	365	**(917)**	363
Debenture and term note issues	**-**	-	**500**	-
Debenture and term note repayments	**-**	(150)	**-**	(150)
Net change in Southern Lights project financing	**(14)**	(16)	**(19)**	(40)
Distributions to noncontrolling interests, net	**(102)**	(60)	**(202)**	(84)
Distributions to redeemable noncontrolling interests, net	**(11)**	(7)	**(23)**	(14)
Preference shares issued	**592**	-	**1,418**	-
Common shares issued	**392**	6	**409**	22
Preference share dividends	**(19)**	(2)	**(34)**	(4)
Common share dividends	**(149)**	(136)	**(305)**	(260)
	58	130	**721**	(171)
Effect of translation of foreign denominated cash and cash equivalents	**6**	(2)	**(6)**	(9)
Increase/(decrease) in cash and cash equivalents	**(427)**	(15)	**(56)**	193
Cash and cash equivalents at beginning of period	**1,094**	584	**723**	376
Cash and cash equivalents at end of period	**667**	569	**667**	569

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2012	December 31, 2011
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**667**	723
Restricted cash	**28**	17
Accounts receivable and other	**3,642**	4,011
Accounts receivable from affiliates	**36**	55
Inventory	**712**	823
	5,085	5,629
Property, plant and equipment, net	**30,665**	28,941
Long-term investments	**3,220**	3,160
Deferred amounts and other assets	**2,602**	2,667
Intangible assets, net	**788**	711
Goodwill	**445**	440
Deferred income taxes	**7**	29
	42,812	41,577
Liabilities and equity		
Current liabilities		
Bank indebtedness	**327**	102
Short-term borrowings	**217**	548
Accounts payable and other	**4,398**	4,764
Accounts payable to affiliates	**28**	48
Interest payable	**190**	185
Environmental liabilities	**125**	175
Current maturities of long-term debt	**758**	354
	6,043	6,176
Long-term debt	**18,428**	19,251
Other long-term liabilities	**2,697**	2,323
Deferred income taxes	**2,463**	2,572
	29,631	30,322
Commitments and contingencies *(Note 12)*		
Redeemable noncontrolling interests	**717**	640
Equity		
Share capital		
Preference shares *(Note 6)*	**2,484**	1,056
Common shares (797 and 781 outstanding at June 30, 2012 and December 31, 2011, respectively) *(Note 6)*	**4,530**	3,969
Additional paid-in capital	**469**	242
Retained earnings	**3,689**	3,926
Accumulated other comprehensive loss *(Note 7)*	**(1,621)**	(1,532)
Reciprocal shareholding *(Note 8)*	**(126)**	(187)
Total Enbridge Inc. shareholders equity	**9,425**	7,474
Noncontrolling interests	**3,039**	3,141
	12,464	10,615
	42,812	41,577

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company s consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with U.S. GAAP and filed with Canadian and United States securities regulators on a voluntary basis (U.S. GAAP Consolidated Financial Statements). In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the Company s financial position as at June 30, 2012 and results of operations and cash flows for the three and six month periods ended June 30, 2012 and 2011. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company s U.S. GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011, except as described in Note 2, Changes in accounting policies. 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 Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements. The Company s 2011 Annual Report included consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with Part V Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook. The Company s U.S. GAAP Consolidated Financial Statements for the three years ended December 31, 2011 were prepared, and voluntarily filed with securities regulators in Canada and the United States, to facilitate users understanding of the transition to U.S. GAAP.

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

2. CHANGES IN ACCOUNTING POLICIES

REGULATION

Enbridge Gas New Brunswick

Based on amendments to the rate setting methodology outlined in a final rates and tariff regulation enacted by the Government of New Brunswick, Enbridge Gas New Brunswick (EGNB) no longer meets the criteria for rate regulated accounting. As a result, effective January 1, 2012, the Company discontinued rate regulated accounting for EGNB.

OTHER

Fair Value Measurement

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board s joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and other comprehensive income (OCI) either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company s presentation of comprehensive income and did not impact the Company s consolidated financial statements.

Goodwill Impairment

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

3. SEGMENTED INFORMATION

Three months ended June 30, 2012	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**527**	**429**	**3,242**	**1,520**	**-**	**5,718**
Commodity and gas distribution costs	**-**	**(140)**	**(3,405)**	**(898)**	**-**	**(4,443)**
Operating and administrative	**(240)**	**(129)**	**(39)**	**(259)**	**(14)**	**(681)**
Depreciation and amortization	**(87)**	**(84)**	**(18)**	**(108)**	**(3)**	**(300)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(23)**	**-**	**(23)**
	200	**76**	**(220)**	**232**	**(17)**	**271**
Income/(loss) from equity investments	**6**	**-**	**26**	**12**	**(10)**	**34**
Other income/(expense)	**13**	**4**	**9**	**8**	**(65)**	**(31)**
Interest expense	**(66)**	**(40)**	**(11)**	**(96)**	**-**	**(213)**
Income taxes recovery/(expense)	**(33)**	**(20)**	**82**	**(47)**	**36**	**18**
Earnings/(loss)	**120**	**20**	**(114)**	**109**	**(56)**	**79**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**(44)**	**-**	**(45)**
Preference share dividends	**-**	**-**	**-**	**-**	**(23)**	**(23)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**119**	**20**	**(114)**	**65**	**(79)**	**11**
Additions to property, plant and equipment1	**441**	**111**	**187**	**406**	**37**	**1,182**

Three months ended June 30, 2011 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	515	475	3,679	2,269	-	6,938
Commodity and gas distribution costs	-	(184)	(3,540)	(1,745)	-	(5,469)
Operating and administrative	(165)	(116)	(34)	(156)	(7)	(478)
Depreciation and amortization	(77)	(79)	(20)	(95)	(3)	(274)
Environmental costs, net of recoveries	-	-	-	(22)	-	(22)
	273	96	85	251	(10)	695
Income from equity investments	2	-	38	14	-	54
Other income/(expense)	71	(3)	10	16	(63)	31
Interest expense	(65)	(41)	(15)	(81)	(34)	(236)
Income taxes recovery/(expense)	(83)	(12)	(41)	(41)	33	(144)
Earnings/(loss)	198	40	77	159	(74)	400
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	(95)	-	(96)
Preference share dividends	-	-	-	-	(2)	(2)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	197	40	77	64	(76)	302
Additions to property, plant and equipment1	175	101	111	206	3	596

Six months ended June 30, 2012 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	**1,123**	**1,346**	**6,528**	**3,348**	**-**	**12,345**
Commodity and gas distribution costs	**-**	**(700)**	**(6,862)**	**(2,101)**	**-**	**(9,663)**
Operating and administrative	**(452)**	**(256)**	**(74)**	**(519)**	**(12)**	**(1,313)**
Depreciation and amortization	**(171)**	**(167)**	**(33)**	**(213)**	**(6)**	**(590)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(26)**	**-**	**(26)**
	500	**223**	**(441)**	**489**	**(18)**	**753**
Income/(loss) from equity investments	**7**	**-**	**54**	**27**	**(16)**	**72**
Other income/(expense)	**17**	**(1)**	**22**	**23**	**(6)**	**55**
Interest expense	**(128)**	**(81)**	**(22)**	**(194)**	**(5)**	**(430)**
Income taxes recovery/(expense)	**(84)**	**(43)**	**163**	**(92)**	**44**	**(12)**
Earnings/(loss)	**312**	**98**	**(224)**	**253**	**(1)**	**438**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(2)**	**-**	**(1)**	**(122)**	**-**	**(125)**
Preference share dividends	**-**	**-**	**-**	**-**	**(38)**	**(38)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**310**	**98**	**(225)**	**131**	**(39)**	**275**
Additions to property, plant and equipment1	**811**	**190**	**336**	**674**	**48**	**2,059**

Six months ended June 30, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	974	1,418	6,591	4,484	-	13,467
Commodity and gas distribution costs	-	(739)	(6,392)	(3,484)	-	(10,615)
Operating and administrative	(315)	(236)	(61)	(364)	(10)	(986)
Depreciation and amortization	(158)	(158)	(39)	(191)	(5)	(551)
Environmental costs, net of recoveries	-	-	-	11	-	11
	501	285	99	456	(15)	1,326
Income from equity investments	2	-	65	30	12	109
Other income/(expense)	71	(8)	20	37	(9)	111
Interest expense	(129)	(85)	(30)	(166)	(56)	(466)
Income taxes recovery/(expense)	(111)	(50)	(50)	(77)	41	(247)
Earnings/(loss)	334	142	104	280	(27)	833
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	(1)	(161)	-	(163)
Preference share dividends	-	-	-	-	(4)	(4)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	333	142	103	119	(31)	666
Additions to property, plant and equipment1	363	165	183	415	7	1,133

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

TOTAL ASSETS

	June 30, 2012	December 31, 2011
(millions of Canadian dollars)		
Liquids Pipelines	**14,838**	12,470
Gas Distribution	**6,647**	7,189
Gas Pipelines, Processing and Energy Services	**5,235**	4,468
Sponsored Investments	**13,592**	13,453
Corporate	**2,500**	3,997
	42,812	41,577

4. ACQUISITION

GREENWICH WINDFARM, LP

On May 31, 2012, Enbridge acquired an additional 10% interest in Greenwich Windfarm, LP (Greenwich), a wind energy project, for cash consideration of $27 million, increasing its ownership interest to 100%. The Company s interest in Greenwich continues to be held within the Gas Pipelines, Processing and Energy Service segment and is consolidated with the Company s results both before and after the acquisition.

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, USA for $190 million (US$190 million). Cash consideration of $7 million (US$7 million) was paid during the first quarter of 2012 and the balance, net of a $1 million (US$1 million) holdback payable, was paid during the second quarter of 2012.

Silver State expands the Company s alternative energy business. Revenue of $3 million and earnings of $1 million were recognized in both the three months and six months ended June 30, 2012. No revenues or earnings were recognized in any prior period, as the solar project commenced operations in the second quarter of 2012. As at June 30 2012, the purchase price allocation was not finalized as the Company had not finalized its valuation of the acquired assets.

5. CREDIT FACILITIES

June 30, 2012	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012-2013	**712**	**224**	**488**
Sponsored Investments	2015-2016	**2,538**	**1,104**	**1,434**
Corporate	2013-2016	**7,540**	**1,383**	**6,157**
		11,090	**2,737**	**8,353**
Southern Lights project financing[1]	2013-2014	**1,520**	**1,450**	**70**
Total credit facilities		**12,610**	**4,187**	**8,423**

1 Total facilities inclusive of $61 million for debt service reserve letters of credit.
2 Total facilities include $30 million in demand facilities with no maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

Credit facilities carry a weighted average standby fee of 0.18% 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 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,447 million (2011 - $3,359 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

6. SHARE CAPITAL

COMMON SHARES

	June 30, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Balance at beginning of period	**781**	**3,969**	770	3,683
Dividend reinvestment and share purchase plan	**4**	**138**	7	229
Shares issued on exercise of stock options	**2**	**35**	4	57
Common shares issued[1]	**10**	**388**	-	-
Balance at end of period	**797**	**4,530**	781	3,969

1 Gross proceeds - $400 million; net issuance costs - $12 million.

11

PREFERENCE SHARES

	June 30, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Preference shares, Series A	**5**	**125**	5	125
Preference shares, Series B	**20**	**490**	20	490
Preference shares, Series D	**18**	**441**	18	441
Preference shares, Series F1	**20**	**490**	-	-
Preference shares, Series H2	**14**	**342**	-	-
Preference shares, Series J3	**8**	**194**	-	-
Preference shares, Series L4	**16**	**402**	-	-
Balance at end of period		**2,484**		1,056

1 *Gross proceeds - $500 million; net issuance costs - $10 million.*
2 *Gross proceeds - $350 million; net issuance costs - $8 million.*
3 *Gross proceeds - US$200 million; net issuance costs - US$4 million.*
4 *Gross proceeds - US$400 million; net issuance costs - US$9 million.*

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend1	Per Share Base Redemption Value2	Redemption and Conversion Option Date2,3	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 H5	4.0%	$1.000	$25	September 1, 2018	Series I
Preference shares, Series J6	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference shares, Series L7	4.0%	US$1.000	US$25	September 1, 2017	Series M

1 *Fixed, cumulative, quarterly preferential dividend per share per year.*
2 *Series A Preference Shares 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 + 2.40% (Series C), 2.37% (Series E), 2.51% (Series G), or 2.12% (Series I)) or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.05% (Series K) or 3.15% (Series M)).*
5 *A cash dividend of $0.4247 per share will be paid on September 1, 2012 to Series H shareholders. The regular quarterly dividend of $0.25 per share will begin in the fourth quarter of 2012.*
6 *A cash dividend of US$0.3699 per share will be paid on September 1, 2012 to Series J shareholders. The regular quarterly dividend of US$0.25 per share will begin in the fourth quarter of 2012.*
7 *A cash dividend of US$0.2767 per share will be paid on September 1, 2012 to Series L shareholders. The regular quarterly dividend of US$0.25 per share will begin in the fourth quarter of 2012.*

Subsequent to June 30, 2012, the Company issued 18 million Series N Preference Shares for gross proceeds of $450 million. The 4.0% Cumulative Redeemable Preference Shares, Series N are entitled to the same dividends, and similar redemption and conversion terms as the other preference shares issued in 2011 and 2012, with all cash payments to be made in Canadian dollars. Redemption of Series N Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series O can occur on December 1, 2018 and on December 1 of every fifth year thereafter. The holders of Series O Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.65%.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company s pro-rata weighted average interest in its own common shares of 18 million and 22 million for the three and six months ended June 30, 2012 (2011 - 23 million and 23 million), resulting from the Company s reciprocal investment in Noverco Inc. (Noverco).

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(number of shares in millions)				
Weighted average shares outstanding	**770**	752	**763**	750
Effect of dilutive options	**13**	10	**12**	10
Diluted weighted average shares outstanding	**783**	762	**775**	760

For the three and six months ended June 30, 2012, there were no anti-dilutive stock options (2011 nil for the three and six months ended) to exclude from the diluted earnings per share calculation.

7. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

	Cash Flow Hedges	Net Investment Hedges	Equity Investees	Pension Plan Adjustment	Cumulative Translation Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2011	(66)	480	(11)	(142)	(1,288)	(1,027)
Changes during the period	48	48	(6)	8	(152)	(54)
Tax impact	(9)	(8)	1	(2)	-	(18)
	39	40	(5)	6	(152)	(72)
Balance at June 30, 2011	(27)	520	(16)	(136)	(1,440)	(1,099)
Balance at January 1, 2012	(476)	461	(28)	(286)	(1,203)	(1,532)
Changes during the period	**(137)**	**(21)**	**4**	**9**	**31**	**(114)**
Tax impact	**29**	**3**	**(5)**	**(2)**	**-**	**25**
	(108)	**(18)**	**(1)**	**7**	**31**	**(89)**
Balance at June 30, 2012	**(584)**	**443**	**(29)**	**(279)**	**(1,172)**	**(1,621)**

8. RECIPROCAL SHAREHOLDING

At December 31, 2011, Noverco owned an approximate 8.9% reciprocal shareholding in the common shares of the Company. On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering, thereby reducing the Company s reciprocal shareholding to 6.0%. Both the Company s equity investment in Noverco, included in Long-term investments, and Equity have increased by $297 million, net of tax, as a result of this transaction. During the second quarter of 2012, the Company received a cash dividend of approximately $317 million from Noverco.

9. 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. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. 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 volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 2.08%.

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 2016. A total of $10,640 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.50%.

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 band 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, power, crude oil and natural gas liquids (NGL). The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGL) that impact earnings from its ownership in the Aux Sable natural gas processing plant and the gathering and processing business held by Enbridge Energy Partners, L.P. (EEP).

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 balance sheet location and carrying value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges at June 30, 2012 or December 31, 2011.

June 30, 2012	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**4**	**15**	**217**	**236**	**-**	**236**
Interest rate contracts	**-**	**-**	**12**	**12**	**(5)**	**7**
Commodity contracts	**26**	**-**	**290**	**316**	**(15)**	**301**
Other contracts	**2**	**-**	**10**	**12**	**-**	**12**
	32	**15**	**529**	**576**	**(20)**	**556**
Deferred amounts and other						
Foreign exchange contracts	**13**	**66**	**160**	**239**	**-**	**239**
Interest rate contracts	**13**	**-**	**17**	**30**	**-**	**30**
Commodity contracts	**19**	**-**	**94**	**113**	**(3)**	**110**
Other contracts	**4**	**-**	**4**	**8**	**-**	**8**
	49	**66**	**275**	**390**	**(3)**	**387**
Accounts payable and other						
Foreign exchange contracts	**(3)**	**-**	**(162)**	**(165)**	**-**	**(165)**
Interest rate contracts	**(614)**	**-**	**(6)**	**(620)**	**5**	**(615)**
Commodity contracts	**(5)**	**-**	**(228)**	**(233)**	**15**	**(218)**
	(622)	**-**	**(396)**	**(1,018)**	**20**	**(998)**
Other long-term liabilities						
Foreign exchange contracts	**(25)**	**(10)**	**(84)**	**(119)**	**-**	**(119)**
Interest rate contracts	**(451)**	**-**	**(16)**	**(467)**	**-**	**(467)**
Commodity contracts	**(5)**	**-**	**(338)**	**(343)**	**3**	**(340)**
	(481)	**(10)**	**(438)**	**(929)**	**3**	**(926)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(11)**	**71**	**131**	**191**	**-**	**191**
Interest rate contracts	**(1,052)**	**-**	**7**	**(1,045)**	**-**	**(1,045)**
Commodity contracts	**35**	**-**	**(182)**	**(147)**	**-**	**(147)**
Other contracts	**6**	**-**	**14**	**20**	**-**	**20**
	(1,022)	**71**	**(30)**	**(981)**	**-**	**(981)**

15

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	4	15	315	334	-	334
Interest rate contracts	-	-	12	12	(4)	8
Commodity contracts	7	-	146	153	(19)	134
Other contracts	3	-	7	10	-	10
	14	15	480	509	(23)	486
Deferred amounts and other						
Foreign exchange contracts	15	79	203	297	-	297
Interest rate contracts	1	-	24	25	(3)	22
Commodity contracts	12	-	241	253	(15)	238
Other contracts	3	-	2	5	-	5
	31	79	470	580	(18)	562
Accounts payable and other						
Foreign exchange contracts	(4)	-	(275)	(279)	-	(279)
Interest rate contracts	(477)	-	(8)	(485)	4	(481)
Commodity contracts	(32)	-	(107)	(139)	19	(120)
	(513)	-	(390)	(903)	23	(880)
Other long-term liabilities						
Foreign exchange contracts	(35)	(5)	(51)	(91)	-	(91)
Interest rate contracts	(415)	-	(20)	(435)	3	(432)
Commodity contracts	(29)	-	(20)	(49)	15	(34)
	(479)	(5)	(91)	(575)	18	(557)
Total net derivative asset/(liability)						
Foreign exchange contracts	(20)	89	192	261	-	261
Interest rate contracts	(891)	-	8	(883)	-	(883)
Commodity contracts	(42)	-	260	218	-	218
Other contracts	6	-	9	15	-	15
	(947)	89	469	(389)	-	(389)

1 *As presented in the Consolidated Statements of Financial Position.*

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

June 30, 2012	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**231**	**55**	**468**	**25**	**25**	**420**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,011**	**1,968**	**2,402**	**2,751**	**2,323**	**2,715**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**1,040**	**3,516**	**3,413**	**3,276**	**3,034**	**3,057**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**2,250**	**3,180**	**2,730**	**1,500**	**980**	**-**
Equity contracts *(millions of Canadian dollars)*	**27**	**27**	**26**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**1**	**47**	**15**	**14**	**1**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**1**	**45**	**38**	**29**	**23**	**27**
Commodity contracts - NGL *(millions of barrels)*	**1**	**1**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**36**	**38**	**40**	**48**	**63**	**58**

16

December 31, 2011	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	58	287	468	25	25	418
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,017	1,865	2,182	2,583	2,039	180
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,227	3,237	2,787	2,641	2,428	215
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	2,650	2,000	1,650	750	-	-
Equity contracts *(millions of Canadian dollars)*	36	26	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	20	59	1	1	1	-
Commodity contracts - crude oil *(millions of barrels)*	11	26	17	8	7	10
Commodity contracts - NGL *(millions of barrels)*	4	1	-	-	-	-
Commodity contracts - power *(MWH)*	40	28	40	48	63	58

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.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(10)**	(23)	**9**	(42)
Interest rate contracts	**(369)**	(63)	**(189)**	15
Commodity contracts	**89**	61	**81**	5
Other contracts	**1**	1	**-**	2
Net investment hedges				
Foreign exchange contracts	**(21)**	5	**(18)**	25
	(310)	(19)	**(117)**	5
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Cash flow hedges				
Foreign exchange contracts[1]	**(1)**	-	**(1)**	-
Interest rate contracts[2]	**10**	5	**24**	9
Commodity contracts[3]	**(5)**	(21)	**(3)**	(30)
Other contracts	**-**	(1)	**-**	(1)
	4	(17)	**20**	(22)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Cash flow hedges				
Interest rate contracts[2]	**4**	(9)	**4**	(9)
Commodity contracts[3]	**(3)**	-	**(5)**	1
	1	(9)	**(1)**	(8)

1 *Reported within Transportation and other services revenue and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*

3 Reported within Commodity costs in the Consolidated Statements of Earnings.

The Company estimates that $62 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 currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 66 months at June 30, 2012.

Non-Qualifying Derivatives

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Foreign exchange contracts1	**(76)**	(20)	**(61)**	2
Interest rate contracts2	**1**	4	**(1)**	4
Commodity contracts3	**(239)**	87	**(442)**	53
Other contracts4	**5**	2	**5**	-
Total unrealized derivative fair value loss	**(309)**	73	**(499)**	59

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments *(Note 12)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at June 30, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

The Company generally has a policy of entering into International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of our 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.

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

(millions of Canadian dollars)	**June 30, 2012**	December 31, 2011
Canadian financial institutions	**436**	431
United States financial institutions	**179**	287
European financial institutions	**99**	257
Other[1]	**220**	112
	934	1,087

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

As at June 30, 2012, the Company has provided letters of credit totaling $210 million in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at June 30, 2012 or December 31, 2011.

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, which is reflected in the fair value. For derivative liabilities, the Company s non-performance risk is considered in the valuation.

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

FAIR VALUE MEASUREMENTS

The Company s financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. Also, the Company 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 is 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.

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company s Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations. The Company does not have any other financial instruments categorized as Level 1.

Level 2

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

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company s held to maturity preferred share investment is primarily based 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 tenure.

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 include long-dated derivative power contracts and NGL and natural gas contracts. 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 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:

June 30, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	**236**	**-**	**236**	**-**	**236**
Interest rate contracts	**-**	**12**	**-**	**12**	**(5)**	**7**
Commodity contracts	**9**	**76**	**231**	**316**	**(15)**	**301**
Other contracts	**-**	**12**	**-**	**12**	**-**	**12**
	9	**336**	**231**	**576**	**(20)**	**556**
Long-term derivative assets						
Foreign exchange contracts	**-**	**239**	**-**	**239**	**-**	**239**
Interest rate contracts	**-**	**30**	**-**	**30**	**-**	**30**
Commodity contracts	**-**	**63**	**50**	**113**	**(3)**	**110**
Other contracts	**-**	**8**	**-**	**8**	**-**	**8**
	-	**340**	**50**	**390**	**(3)**	**387**
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	**-**	**(165)**	**-**	**(165)**	**-**	**(165)**
Interest rate contracts	**-**	**(620)**	**-**	**(620)**	**5**	**(615)**
Commodity contracts	-	**(136)**	**(97)**	**(233)**	**15**	**(218)**
	-	**(921)**	**(97)**	**(1,018)**	**20**	**(998)**
Long-term derivative liabilities						
Foreign exchange contracts	**-**	**(119)**	**-**	**(119)**	**-**	**(119)**
Interest rate contracts	**-**	**(467)**	**-**	**(467)**	**-**	**(467)**
Commodity contracts	**-**	**(300)**	**(43)**	**(343)**	**3**	**(340)**
	-	**(886)**	**(43)**	**(929)**	**3**	**(926)**
Total net financial asset/(liability)						
Foreign exchange contracts	**-**	**191**	**-**	**191**	**-**	**191**
Interest rate contracts	**-**	**(1,045)**	**-**	**(1,045)**	**-**	**(1,045)**
Commodity contracts	**9**	**(297)**	**141**	**(147)**	**-**	**(147)**
Other contracts	**-**	**20**	**-**	**20**	**-**	**20**
	9	**(1,131)**	**141**	**(981)**	**-**	**(981)**

December 31, 2011 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	334	-	334	-	334
Interest rate contracts	-	12	-	12	(4)	8
Commodity contracts	1	66	86	153	(19)	134
Other contracts	-	10	-	10	-	10
	1	422	86	509	(23)	486
Long-term derivative assets						
Foreign exchange contracts	-	297	-	297	-	297
Interest rate contracts	-	25	-	25	(3)	22
Commodity contracts	-	208	45	253	(15)	238
Other contracts	-	5	-	5	-	5
	-	535	45	580	(18)	562
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	-	(279)	-	(279)	-	(279)
Interest rate contracts	-	(485)	-	(485)	4	(481)
Commodity contracts	-	(59)	(80)	(139)	19	(120)
	-	(823)	(80)	(903)	23	(880)
Long-term derivative liabilities	-					
Foreign exchange contracts	-	(91)	-	(91)	-	(91)
Interest rate contracts	-	(435)	-	(435)	3	(432)
Commodity contracts	-	(30)	(19)	(49)	15	(34)
	-	(556)	(19)	(575)	18	(557)
Total net financial asset/(liability)						
Foreign exchange contracts	-	261	-	261	-	261
Interest rate contracts	-	(883)	-	(883)	-	(883)
Commodity contracts	1	185	32	218	-	218
Other contracts	-	15	-	15	-	15
	1	(422)	32	(389)	-	(389)

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

	Fair value at June 30, 2012 *(millions of Canadian dollars)*	**Unobservable Input**	**Minimum Price**	**Maximum Price**	**Weighted Average Price**	
Commodity Contracts - Financial[1]						
Natural Gas	2	Forward Gas Price	2.72	3.90	3.09	$/mmbtu[3]
Crude	10	Forward Crude Price	57.54	86.41	79.61	$/barrel
NGL	56	Forward NGL Price	0.07	1.87	0.82	$/gallon
Power	(2)	Forward Power Price	65.00	89.75	70.63	$/MWH
Commodity Contracts - Physical[1]						
Natural Gas	7	Forward Gas Price	2.43	6.56	3.71	$/mmbtu[3]
Crude	47	Forward Crude Price	63.70	103.78	85.35	$/barrel
NGL	3	Forward NGL Price	0.24	2.19	0.95	$/gallon
Power	(2)	Forward Power Price	24.09	35.72	32.15	$/MWH
Commodity Options[2]						
Natural Gas	2	Option Volatility	26%	37%	33%	
NGL	18	Option Volatility	38%	119%	85%	

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 would result in significantly different fair values for long positions, with offsetting impacts to short positions. 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 instruments classified as Level 3 in the fair value hierarchy were as follows:

	Six months ended June 30,	
	2012	2011
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**32**	(24)
Total gains/(losses), unrealized		
Included in earnings[1]	**65**	(14)
Included in OCI	**50**	(43)
Settlements	**(6)**	50
Level 3 net derivative asset/(liability) at end of period	**141**	(31)

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

The Company s policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at June 30, 2012 or 2011.

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. At June 30, 2012 and December 31, 2011, all equity investments of this nature held by the Company are recognized at cost with a carrying value of $53 million at June 30, 2012 (December 31, 2011 - $56 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $261 million at June 30, 2012 (December 31, 2011 - $285 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 4.34% to 4.40%. At June 30, 2012, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2011 - $580 million).

At June 30, 2012, the Company s long-term debt had a carrying value of $19,186 million (December 31, 2011 - $19,605 million) and a fair value of $21,878 million (December 31, 2011 - $22,620 million).

10. INCOME TAXES

Significant variances between the effective income tax rate and the weighted average Canadian statutory income tax rate were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
Canadian weighted average statutory tax rate	**25.7%**	25.5%	**25.7%**	25.5%
Foreign rate differential[1]	**(42.2%)**	1.8%	**(13.0%)**	1.2%
Other	**(13.1%)**	(1.0%)	**(10.1%)**	(3.8%)
	(29.6%)	26.3%	**2.6%**	22.9%

1 *The effective income tax rate decreased significantly from the prior year substantially as a result of losses arising on certain risk management activities in the Company s United States operations. The benefit was due to the higher United States income tax rate over the Canadian weighted average statutory tax rate.*

11. RETIREMENT AND POSTRETIREMENT BENEFITS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, 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. The Company also provides other postretirement benefits (OPEB) for qualifying retired employees. Costs related to the period are presented below.

24

NET BENEFIT COSTS RECOGNIZED

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Benefits earned during the period	**25**	16	**48**	33
Interest cost on projected benefit obligations	**20**	21	**41**	42
Expected return on plan assets	**(24)**	(23)	**(48)**	(47)
Amortization of prior service costs	**-**	-	**-**	1
Amortization of actuarial loss	**6**	6	**12**	12
Net benefit costs[1]	**27**	20	**53**	41

1 *Included in net benefit costs for the three and six months ended June 30, 2012 are costs related to OPEB of $5 million and $9 million, respectively (2011 - $4 million and $7 million).*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Six months ended June 30,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Contributions paid	**34**	30	**2**	2
Contributions expected to be paid in the next six months	**72**		**9**	
Total contributions expected to be paid in the year	**106**		**11**	

12. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,167 million which are expected to be paid within the next five years.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP with its earnings, net of noncontrolling interests, reflected within the Sponsored Investments segment.

Line 6B Crude Oil Release

During the second quarter of 2012, cleanup of the areas affected by the Line 6B crude oil release that occurred in July 2010 near Marshall, Michigan allowed the Kalamazoo River and Morrow Lake to be re-opened for recreational use. EEP will continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations including remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives that EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) related to the Line 6B crude oil release, which indicated a US$3.7 million civil penalty. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety Board presented the results of its investigation into the Line 6B crude oil release and subsequently posted its final report on July 26, 2012.

As a result of additional work needed as noted above, and the civil penalty assessed by PHMSA, EEP has revised the total estimate for costs to US$785 million ($131 million after-tax attributable to Enbridge) for this incident, before insurance recoveries, and excluding fines and penalties which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above, as at June 30, 2012, an increase of US$20 million ($2 million after-tax attributable to Enbridge) from March 31, 2012. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at June 30, 2012. 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

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. 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 in May of each year. The program 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 June 30, 2012, Enbridge and its affiliates have exceeded the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received insurance payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. At June 30, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP s insurance policies during the period that EEP deems realization of the claim for recovery to be probable. EEP recognized US$15 million ($3 million after-tax attributable to Enbridge) and US$50 million ($8 million after-tax attributable to Enbridge) of insurance recoveries for the three and six months ended June 30, 2011, respectively.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed 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 these actions to be material. On July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of US$3.7 million. 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 a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

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

OTHER LITIGATION

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