ENBRIDGE INC
Form 6-K
November 09, 2011

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 November 9, 2011

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. 333-152607 AND 333-170200) 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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 November 9, 2011
- Interim Report to Shareholders for the nine months ended September 30, 2011.

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: November 9, 2011

By: /s/ Alison T. Love
Alison T. Love
Vice President, Corporate Secretary &
Chief Compliance Officer

NEWS RELEASE

Enbridge reports third quarter adjusted earnings of $241 million or $0.32 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- Third quarter earnings were $4 million after unrealized non-cash mark-to-market accounting impacts; year-to-date earnings were $656 million, or $0.87 per common share

- Third quarter and nine month adjusted earnings were $241 million, or $0.32 per common share, and $835 million, or $1.11 per common share, respectively

- $1.2 billion project to twin Athabasca Pipeline to add capacity for growing oil sands production

- Expansion of the Partnership s Line 5 and reversal of a segment of the Company s Line 9 to expand access to eastern markets for western crude oil

- $1.1 billion investment in Cabin Gas Plant Development marks entry into Canadian midstream natural gas

- Montana Alberta Tie Line Project marks entry into power transmission business

- Renewable energy infrastructure platform grows with $0.3 billion investment in the Lac Alfred Wind Project in Quebec

- $1.2 billion transfer of renewable assets to Enbridge Income Fund provides an attractive source of capital

CALGARY, ALBERTA, November 9, 2011 Enbridge Inc. (TSX:ENB) (NYSE:ENB) Enbridge s performance through the third quarter of 2011 continues to reflect strong growth and we are now trending to finish the year near or slightly above the top end of our adjusted earnings per share guidance range of $1.38 to $1.48, said Patrick D. Daniel, President and Chief Executive Officer. Over the quarter, and year-to-date, we have also experienced significant cash flow growth that is strengthening our already solid financial position. This higher cash flow is being generated by the large suite of energy infrastructure projects that we have completed and placed into service over the last year; and there is more to come.

Based on the $10 billion of growth projects we have secured and that are underway, coupled with the very large suite of growth opportunities, we remain confident of delivering a 10% average annual growth rate in adjusted earnings per share into the middle of this decade.

Third quarter 2011 results reflected unrealized non-cash mark-to-market accounting impacts, primarily related to the comprehensive long-term economic hedging program Enbridge has put in place to mitigate exposures to foreign exchange risks, including those exposures inherent within the new Competitive Toll Settlement (CTS). These kinds of short-term non-cash impacts to reported earnings are a by-product of Enbridge s hedging program, which over the long-term will support the Company s reliable cash flows and dividend growth.

Over the third quarter and beginning of the fourth quarter, Enbridge announced several growth projects in its liquids pipelines and gas transportation and processing businesses, as well as developments in renewable energy and power transmission.

In the oil sands region, the twinning of the Athabasca Pipeline, announced in early September, is designed to accommodate the need for additional capacity to serve Kirby area oil sands growth. At an estimated cost of $1.2 billion, the twin pipeline will have an initial capacity of approximately 450,000 barrels per day (bpd), with expansion potential to 800,000 bpd.

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.

Expansion of Enbridge Energy Partners L.P. s (EEP or the Partnership) Line 5 and reversal of the segment of Enbridge s Line 9 from Sarnia to Westover, announced in early October, will provide increased access to refineries in the U.S. upper midwest and in Ontario, Canada for light crude oil produced in western Canada and the U.S.

The Wrangler Pipeline, announced in late September, is a proposed joint venture project with Enterprise Products Partners that would transport crude oil from the oversupplied hub at Cushing, Oklahoma to the Texas Gulf Coast refining complex. Enbridge is also developing the Flanagan South Project proposal that would add additional capacity from its terminal at Flanagan, Illinois to Cushing.

During the quarter, Enbridge filed with the National Energy Board commercial agreements which set terms for long-term service on both the proposed Northern Gateway crude oil export pipeline and the condensate import pipeline. Commercial support for the project from both Canadian oil producers and Asian markets reinforces the international importance of the project to Canada - facilitating access to world markets and international pricing for Canada s most valuable non-renewable resource, said Mr. Daniel.

In early October, Enbridge announced a substantial initial step in the execution of its strategy to establish a strong position in the Canadian Midstream natural gas business with the acquisition of a majority interest in the Cabin Gas Plant Development for approximately $900 million. Enbridge subsequently acquired an additional 13.3% interest in the development in early November, bringing its total interest to 71.0% and its investment to approximately $1.1 billion.

Midstream gas infrastructure in western Canada is an area of excellent growth potential given the positive gas and natural gas liquids fundamentals. Our investment in the Cabin Gas Plant Development establishes our presence in the prolific Horn River natural gas play, said Mr. Daniel. Phases 1 and 2 of Cabin are expected to generate an attractive, low-risk return and align very well with Enbridge s reliable business model. The investment also comes with growth potential from future development of phases 3 through 6.

Enbridge s power generation and new transmission business also marked milestones in the quarter. In September, Enbridge celebrated the opening of the Company s first U.S. wind project, the 250-megawatt Cedar Point project, ahead of schedule and under budget. In early October, Enbridge completed the acquisition of the Montana-Alberta Tie-Line (MATL) project.

Power transmission represents an attractive opportunity for Enbridge with strong industry fundamentals and growth potential and the acquisition of the Montana-Alberta Tie-Line project is an excellent entry point, said Mr. Daniel. The MATL project has great fundamentals in terms of the Montana to Alberta power price differential, is fully contracted and has low cost expansion potential. We plan to build on this initial base to continue to grow within the power transmission sector.

The announcement in early November of Enbridge s investment in the Lac Alfred Wind Project in Quebec grew the Company s interests in renewable and alternative generating capacity by more than 1,150 megawatts. The Lac Alfred project marks Enbridge s entry into the growing Quebec wind energy market and advances our strategy to invest in renewable energy infrastructure as part of a sustainable power generation platform with sold returns, stable cash flow and environmental benefits, said Mr. Daniel.

In October, Enbridge transferred a portfolio of renewable energy assets to Enbridge Income Fund (the Fund) for $1.2 billion. The transfer enhanced the distributable cash flow of the Fund while providing Enbridge with a lower cost source of capital with which to fund these assets.

Mr. Daniel said the Company s future outlook continues to be encouraging.

We have a much bigger and more broadly based suite of opportunities before us than the Company has ever had before, noted Mr. Daniel. We have a record slate of liquids pipeline growth opportunities, a very buoyant gas pipeline and processing picture largely driven by shale gas plays, continuing opportunities to grow our renewable and alternative energy portfolio and excellent momentum within the power transmission sector.

Underpinning our growth story is a strong balance sheet and financial flexibility that enables us to capture these opportunities, together with an uncompromising focus on operational safety and integrity across all of our operations and assets.

THIRD QUARTER 2011 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 of $4 million for the third quarter of 2011 have decreased compared with the third quarter of 2010 substantially due to the recognition of net unrealized fair value losses on financial derivatives, primarily used to manage long-term exposures to foreign exchange risks, including those inherent within the Competitive Toll Settlement (CTS) which took effect July 1, 2011.

- After adjusting earnings for non-recurring or non-operating items, including a charge, net of insurance recoveries, of $8 million associated with the Line 6B crude oil release and unrealized derivative fair value gains and losses, third quarter 2011 adjusted earnings were $241 million compared with $196 million in the prior year comparative period. Adjusted earnings were positively impacted by earnings growth on the Canadian Mainline and the Regional Oil Sands System, as well as strong contributions from Energy Services resulting from improved margin opportunities in crude oil marketing. Enbridge Energy Partners, L.P. (EEP) also made a positive contribution to adjusted earnings relative to the prior period as a result of higher volumes in the natural gas business, as well as the impact of new assets placed into service and the Elk City System acquired in September 2010.

- On November 3, 2011, Enbridge announced agreement with EDF EN Canada Inc. under which Enbridge will invest approximately $0.3 billion to acquire a 50% interest in and become co-owner of the 300-megawatt (MW) Lac Alfred Wind Project. The project, located 400 kilometres (250 miles) northeast of Quebec City in Quebec s Bas-Saint-Laurent region, will consist of 150 wind turbines. Construction will be completed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1, which began in June 2011, 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 power purchase agreement and will construct the 30-kilometre transmission line to connect the Lac Alfred Wind Project to the grid under an interconnection agreement.

- In October 2011, the Company announced it reached agreement with Encana Corporation, on behalf of certain co-owners of the Cabin Gas Plant Development (Cabin), whereby Enbridge will become the majority owner in the development located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. Under the terms of the Asset Purchase and Sale agreement, Enbridge will acquire a 57.7% interest in phases 1 and 2 of Cabin which together will be capable of processing 800 million cubic feet per day (mmcf/d) of natural gas.

Phase 1 of the development will have 400 mmcf/d of natural gas processing capacity. The plant is currently under construction and is expected to be in-service in the third quarter of 2012. Phase 2 will add an additional 400 mmcf/d of capacity and has been sanctioned by the producers and received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. Horn River producers can request the Company to expand Cabin up to an additional four phases.

On November 2, 2011, the Company announced it had reached agreement to acquire an additional interest in Cabin, increasing Enbridge s ownership interest to 71.0%. Upon completion of phases 1 and 2, the Company s total investment is expected to be approximately $1.1 billion.

- On October 28, 2011, EEP announced the Bakken Access Program, a series of projects totaling approximately US$0.1 billion, which represents an upstream expansion that will further complement its 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, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

- On October 21, 2011, Enbridge completed the transfer of the Ontario Wind, Sarnia Solar and Talbot Wind energy projects to Enbridge Income Fund (the Fund) for an aggregate price of $1.2 billion. The transaction was financed by the Fund through a combination of debt and equity, including the issuance of additional ordinary trust units of the Fund to both Enbridge Income Fund Holdings Inc. and Enbridge. Enbridge s overall economic interest in the Fund was reduced from 72% to 69% upon completion of the transaction and associated financing.

- On October 13, 2011, Enbridge announced the acquisition of all outstanding common shares of Tonbridge Power Inc. (Tonbridge) for $20 million. Enbridge repaid approximately $50 million of debt incurred by Tonbridge in the development of the Montana-Alberta Tie-Line (MATL) project and will also inject further funding to complete the first 300-MW phase of MATL, as well as an expansion to 550-MW. The total expected cost to complete both phases of MATL is approximately $0.3 billion, of which approximately half is being funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy.

The MATL project is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of growing supply of electric power in Montana and the buoyant power demand in Alberta. Required permits for the first phase of MATL have been obtained and the project has secured long-term, take-or-pay contracts for the system s entire initial northbound capacity, with in-service expected in mid-2012.

- On October 3, 2011, Enbridge and EEP announced two projects that will 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. The project involves the expansion of EEP s Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 barrels per day (bpd), at a total cost of approximately $0.1 billion. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of Line 9 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, both projects are expected to be in service in late 2012.

- On September 30, 2011, Enbridge completed a $500 million public offering of cumulative redeemable Preferred Shares, Series B. The proceeds will be used for capital expenditures, to repay indebtedness and for other general corporate purposes.

- On September 29, 2011, Enbridge and Enterprise Product Partners, L.P. (Enterprise) announced plans to develop a new pipeline to transport crude oil from Enbridge s Cushing, Oklahoma facility to the Texas Gulf Coast refining complex. The 800-kilometre (500-mile) 36-inch diameter Wrangler Pipeline would have an initial capacity of up to 800,000 bpd and a target in-service date of mid-2013. An Open Season for the project began in October 2011.

- On September 27, 2011, Alliance Pipeline US announced 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. Alliance US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products and Hess have reached a concurrent agreement for the provision of natural gas liquids (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 120 mmcf/d, which can be expanded based on shipper demand. Subject to regulatory and other required approvals, the pipeline is expected to be in service by the third quarter of 2013.

- On September 12, 2011, Enbridge announced plans to twin the southern section of its Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve Kirby Lake area expected oil sands growth. The twinning project, at 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 capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the line is expected to be capable of accepting initial volumes by early 2015, with full capacity available by 2016.

- On September 6, 2011, EEP announced a joint venture with Enterprise and Anadarko Petroleum Corporation 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 Texas Express Pipeline (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 will have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. 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; the second will connect TEP to central Texas, Barnett Shale processing plants. Subject to regulatory approvals, the pipeline and portions of the gathering systems are expected to begin service in the second quarter of 2013.

- On August 24, 2011, Enbridge announced that Enbridge Northern Gateway Pipelines had filed with the National Energy Board commercial agreements for committed long-term service on both the proposed crude oil export pipeline and the condensate import pipeline. After negotiations with Canadian producers and Asian markets, the parties, who remain confidential, have agreed on commercial terms relating to the long-term use of the facilities.

- On August 8, 2011, EEP announced plans to construct an additional processing plant and other facilities on its Anadarko system at an approximate cost of US$0.2 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013.

DIVIDEND DECLARATION

On October 28, 2011, the Enbridge Board of Directors declared quarterly dividends of $0.245 per common share and $0.34375 per Series A Preferred Share. Both dividends are payable on December 1, 2011 to shareholders of record on November 15, 2011.

CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, November 9, 2011 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the third quarter 2011 results. Analysts, members of the media and other interested parties can access the call at +857-350-1666 or toll-free at 1-866-804-6920 using the access code of 74708687. The call will be audio webcast live at www.enbridge.com/InvestorRelations.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 54567900) will be available until November 16, 2011.

The conference call will begin with a presentation by the Company s Chief Executive Officer and Chief Financial Officer followed by a question and answer period for investment analysts. A question and answer period for members of the media will 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 growing involvement in the natural gas transmission and midstream businesses, and is expanding its interests in renewable and green energy technologies including wind and solar energy, hybrid fuel cells and carbon dioxide sequestration. 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 approximately 6,400 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.

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 , estima forecast , plan , intend , target , believe and similar words suggesting future outcomes or statements regarding an ou 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; prices of crude oil, natural gas and natural gas liquids; 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 natural gas liquids, 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 Canadian generally accepted accounting principles (Canadian GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers.

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HIGHLIGHTS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders				
Liquids Pipelines	**(31)**	128	**302**	395
Gas Distribution	**(2)**	(5)	**142**	95
Gas Pipelines, Processing and Energy Services	**51**	19	**136**	89
Sponsored Investments	**63**	(28)	**185**	81
Corporate	**(77)**	43	**(109)**	(23)
	4	157	**656**	637
Earnings per common share[1]	**0.01**	0.21	**0.87**	0.86
Diluted earnings per common share[1]	**0.01**	0.21	**0.86**	0.85
Adjusted earnings[2]				
Liquids Pipelines	**150**	128	**410**	395
Gas Distribution	**(2)**	(5)	**129**	113
Gas Pipelines, Processing and Energy Services	**39**	31	**122**	92
Sponsored Investments	**63**	59	**175**	161
Corporate	**(9)**	(17)	**(1)**	(15)
	241	196	**835**	746
Adjusted earnings per common share[1]	**0.32**	0.26	**1.11**	1.01
Cash flow data				
Cash provided by operating activities	**719**	319	**2,251**	1,476
Cash used in investing activities	**(751)**	(741)	**(1,838)**	(1,928)
Cash provided by/(used in) financing activities	**289**	490	**(89)**	597
Dividends				
Common share dividends declared	**191**	163	**569**	485
Dividends paid per common share[1]	**0.245**	0.2125	**0.735**	0.6375
Shares outstanding *(millions)*				
Weighted average common shares outstanding[1]	**750**	743	**751**	739
Diluted weighted average common shares outstanding[1]	**761**	751	**760**	746
Operating data				
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*				
Canadian Mainline[3]	**2,337**	2,178	**2,243**	2,141
Regional Oil Sands System[4]	**345**	307	**322**	279
Spearhead Pipeline	**56**	142	**91**	139
Gas Distribution - Enbridge Gas Distribution				
Volumes *(billions of cubic feet)*	**43**	45	**311**	277
Number of active customers *(thousands)*[5]	**1,973**	1,942	**1,973**	1,942
Heating degree days[6]				
Actual	**55**	79	**2,506**	2,151
Forecast based on normal weather	**82**	83	**2,379**	2,336
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,495**	1,551	**1,562**	1,604
Vector Pipeline	**1,359**	1,329	**1,500**	1,399
Enbridge Offshore Pipelines	**1,509**	1,998	**1,664**	1,983

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 in Western Canada and to the Lakehead System at the United States border as well as Line 8 and Line 9 in Eastern 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 Enbridge Gas Distribution 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 Enbridge Gas Distribution 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

September 30, 2011

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2011

This Management s Discussion and Analysis (MD&A) dated November 8, 2011 should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and nine months ended September 30, 2011, which are prepared in accordance with Part V - Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company s Annual Report for the year ended December 31, 2010. 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.

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.

CONSOLIDATED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**(31)**	128	**302**	395
Gas Distribution	**(2)**	(5)	**142**	95
Gas Pipelines, Processing and Energy Services	**51**	19	**136**	89
Sponsored Investments	**63**	(28)	**185**	81
Corporate	**(77)**	43	**(109)**	(23)
Earnings attributable to common shareholders	**4**	157	**656**	637
Earnings per common share[1]	**0.01**	0.21	**0.87**	0.86
Diluted earnings per common share[1]	**0.01**	0.21	**0.86**	0.85

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

Earnings attributable to common shareholders were $4 million for the three months ended September 30, 2011, or $0.01 per common share, compared with $157 million, or $0.21 per common share, for the three months ended September 30, 2010. 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, including such exposures inherent within the Competitive Toll Settlement (CTS) which took effect July 1, 2011. The Company also continues to experience lower volumes, and therefore lower earnings contributions, from its Enbridge Offshore Pipelines (Offshore) assets. Partially offsetting unrealized derivative losses and weakness in the Offshore segment are strong contributions from Canadian Mainline and the Company s Energy Services businesses. For the three months ended September 30, 2011, a charge, net of insurance recoveries, associated with the Line 6B crude oil release of $8 million was reflected in earnings from Enbridge Energy Partners, L.P. (EEP), compared with an $85 million charge for the third quarter of 2010.

Earnings attributable to common shareholders were $656 million for the nine months ended September 30, 2011, or $0.87 per common share, compared with $637 million, or $0.86 per common share, for the nine months ended September 30, 2010. This increase primarily reflected increased earnings from Enbridge Gas Distribution (EGD) due to favourable operating performance and the impact of colder weather, and stronger contributions from the Regional Oil Sands System, Energy Services and the

Company s green energy assets presented within the Gas Pipelines, Processing and Energy Services segment. These positive factors were partially offset by the recognition of higher net unrealized fair value losses on financial derivatives and lower contributions from Offshore. Earnings for the nine months ended September 30, 2011 also included a charge, net of insurance recoveries, to earnings from EEP associated with the Lines 6A and 6B crude oil releases of $6 million (2010 - $85 million).

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 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; prices of crude oil, natural gas and natural gas liquids; 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 natural gas liquids, 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

3

earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**150**	128	**410**	395
Gas Distribution	**(2)**	(5)	**129**	113
Gas Pipelines, Processing and Energy Services	**39**	31	**122**	92
Sponsored Investments	**63**	59	**175**	161
Corporate	**(9)**	(17)	**(1)**	(15)
Adjusted earnings	**241**	196	**835**	746
Adjusted earnings per common share[1]	**0.32**	0.26	**1.11**	1.01

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

Adjusted earnings were $241 million, or $0.32 per common share, for the three months ended September 30, 2011 compared with $196 million, or $0.26 per common share, for the three months ended September 30, 2010. Adjusted earnings were $835 million, or $1.11 per common share, for the nine months ended September 30, 2011 compared with $746 million, or $1.01 per common share, for the nine months ended September 30, 2010.

The following factors impacted the increase in adjusted earnings for both the three and nine months ended September 30, 2011 compared with the corresponding periods of 2010.

- Within Liquids Pipelines, stronger contributions from the Canadian Mainline and the Regional Oil Sands System.
- Continued positive performance at EGD reflecting favourable operating performance under the current Incentive Regulation term.
- Within Gas Pipelines, Processing and Energy Services, improved margins in crude oil marketing and the positive contribution from newly completed green energy facilities, offset by weak results from Offshore assets.
- Higher earnings for Sponsored Investments resulting from increased earnings in the natural gas business and higher incentive income from EEP.
- Lower financing charges in the Corporate segment.

RECENT DEVELOPMENTS

LIQUIDS PIPELINES

Competitive Toll Settlement

On June 24, 2011, the National Energy Board (NEB) approved the 10-year CTS agreement reached between Enbridge and shippers on its mainline system. The CTS took effect for toll making on the mainline system (with the exception of Line 8 and Line 9) on July 1, 2011. Under the terms of the CTS, the initial Canadian local toll was based on the 2011 Incentive Tolling Settlement (ITS) approved by the NEB earlier this year. The Canadian local toll will then be adjusted annually on July 1st by 75% of the Canada Gross Domestic Product at Market Price Index for each of the remaining nine years of the settlement. The CTS also provides for an International Joint Tariff (IJT) for crude oil shipments originating in Canada on the mainline system and delivered in the United States off the Lakehead System (the portion of the mainline in the United States that is owned by the Company s affiliate EEP) and into eastern Canada. The IJT, which is based on a fixed toll for the term of the settlement that was negotiated between Enbridge and shippers, will be adjusted annually by the same factor as the Canadian Local Toll and in limited other circumstances.

Local tolls for service on the Lakehead System will not be affected by the CTS and will continue to be established by EEP s existing toll agreements. Furthermore, the revenues received by the Company for mainline service in Canada under the IJT will be adjusted annually during each of the remaining nine years of the CTS to ensure that EEP receives the revenues it would have received if it had charged the local tolls in effect from time-to-time. The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System.

Christina Lake Lateral Project

The Christina Lake Lateral Project includes a new pipeline terminal and blended products pipeline, which will allow the Cenovus and ConocoPhillips partnership to deliver increased Christina Lake production volumes directly into the Athabasca Pipeline. Having achieved substantial completion in August 2011, the expansion project has added two 375,000 barrel tanks and 26 kilometres (16 miles) of 30-inch diameter pipeline to the existing Christina Lake lateral and terminal facilities, which include two eight-inch lateral lines and 240,000 barrels of tankage, that connect to the Athabasca Pipeline. The estimated final cost of the additional facilities is approximately $0.2 billion.

Woodland Pipeline

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited (Imperial Oil) and ExxonMobil Canada Properties (ExxonMobil) 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. The Woodland Pipeline is being undertaken as a joint venture between Enbridge, Imperial Oil and ExxonMobil. Regulatory approval for the Phase I facilities was received in June 2010 and construction is underway. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, with expenditures to date of approximately $0.1 billion. Enbridge expects the pipeline will come into service in late 2012.

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. 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. With regulatory approval received in the first quarter of 2011, the expansion is expected to be completed in 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 of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton mainline hub. 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 $0.1 billion. With regulatory approval received in the first quarter of 2011, the new pipeline is expected to be in service by late 2012.

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company will construct a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5

billion. With regulatory approval received in the second quarter of 2011, the facilities are expected to be in service in late 2013.

Waupisoo Pipeline Expansion

The Waupisoo Pipeline Expansion, which received regulatory approval in November 2010, will provide 65,000 barrels per day (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 project will accommodate additional shipper commitments of 229,000 bpd. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion.

Athabasca Pipeline Capacity Expansion

The Company will undertake an expansion of its Athabasca Pipeline to its full capacity to accommodate additional throughput including incremental capacity required to serve expansion of the Christina Lake Oilsands Project operated by Cenovus. This expansion will increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on crude type. The estimated cost of this expansion is approximately $0.4 billion with an expected in service date of 2013 for the expansion to 430,000 bpd of capacity with the balance of the additional capacity 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.

Athabasca Pipeline Twinning

In September 2011, Enbridge announced plans to twin the southern section of its Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve Kirby Lake area expected oil sands growth. The twinning project, at 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 capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the line is expected to be capable of accepting initial volumes by early 2015, with full capacity available by 2016.

Wrangler Pipeline

In September 2011, Enbridge and Enterprise Product Partners, L.P. (Enterprise) announced plans to develop a new pipeline to transport crude oil from Enbridge s Cushing, Oklahoma terminal to the Texas Gulf Coast refining complex. The 800-kilometre (500-mile) 36-inch diameter Wrangler Pipeline would have an initial capacity of up to 800,000 bpd and a target in-service date of mid-2013. An Open Season for the project began in October 2011.

Flanagan South Project

The Company is holding a binding Open Season offering additional crude oil transportation capacity from its terminal at Flanagan, Illinois to Cushing, Oklahoma. Subject to regulatory approval and sufficient long-term commitments from shippers, capacity could be available by mid-2014.

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 on May 27, 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. The JRP conducted sessions with the public, including Aboriginal groups, to receive comments on the draft List of Issues, additional information which Northern Gateway should be required to file and locations for the oral hearings. The JRP decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. In January 2011, the JRP issued a decision requiring Northern Gateway to provide certain additional information on the design and risk assessment of the pipelines before it would issue a Hearing Order. This information, together with other updates regarding the project, was provided to the JRP in March 2011. The JRP subsequently issued a Hearing Order outlining the procedures to be followed and has indicated that hearings will be held starting in January 2012.

In June 2011, Northern Gateway filed additional materials with the JRP including, but not limited to, details of its extensive program of consultation with over 40 Aboriginal communities between December 2009 and March 2011. The update summarized the information provided to Aboriginal groups, the engagement activities that have occurred, the interests and concerns that have been expressed to Northern Gateway, commitments and mitigation measures in response to those concerns, and an update on the status of Aboriginal Traditional Knowledge study programs. In August 2011, Northern Gateway filed with the NEB commercial agreements for committed long-term service on both the proposed crude oil export and condensate import pipelines.

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 by 2017 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured 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.

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 Corporate 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.

Fort Hills Pipeline System

In late 2008, Fort Hills Energy L.P. (FHELP) announced that its final investment decision for the mining portion of the project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. FHELP has now completed its re-evaluation and while it is proceeding with the mining portion of the project, FHELP has decided not to proceed with the original pipeline project. Expenditures incurred to date under the original contractual arrangement of approximately $0.1 billion have substantially been collected from FHELP. Discussions on a new pipeline project to meet the new needs of the mining project are ongoing, with no commitments currently in place.

Norman Wells Crude Oil Release

On May 9, 2011, Enbridge reported a crude oil release from a pipeline on its Norman Wells System approximately 50 kilometres south of the community of Wrigley, Northwest Territories (NWT). On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Based on current estimates provided by third party experts on site, Enbridge estimates the release volume was approximately 1,500 barrels. Remediation activities are ongoing. The Norman Wells Pipeline is a 12-inch, 39,400 bpd line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, Alberta. Currently, Management does not believe this incident will have a material impact on the Company s consolidated financial position or results of operations.

GAS DISTRIBUTION

Nexus Project

The Nexus Project is a 4.5 billion cubic feet (bcf) expansion of EGD s unregulated natural gas storage facility at Tecumseh, near Sarnia, Ontario with an expected capital cost of $42 million. The project, which has received regulatory approval, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and is expected to be completed in the fourth quarter of 2011.

Enbridge Gas New Brunswick Transition to Cost-Based Natural Gas Distribution Rates

On November 23, 2010, Enbridge Gas New Brunswick Limited Partnership (EGNB) applied to the New Brunswick Energy and Utilities Board (NBEUB) to raise its natural gas distribution rates in the Province of New Brunswick in order to recover more of the costs of operating its natural gas delivery system in the province. Some of EGNB s large-user class customers have expressed significant opposition to the market-based rate setting mechanism that currently applies to EGNB, including public requests by some of these customers for the Province of New Brunswick to legislate a reduction in natural gas distribution rates for large-user customers. EGNB is currently engaged in discussions with the Government of New Brunswick with respect to potential amendments to EGNB s General Franchise Agreement with the Province of New Brunswick, which may include changes to the current system under which EGNB charges market-based rates. The potential financial impact of negotiations with the Government of New Brunswick is not yet determinable. Given the ongoing negotiations with the Government of New Brunswick and the potential that these negotiations may result in changes to EGNB s rate setting mechanism, EGNB asked the NBEUB to suspend its application to increase rates paid by its large-user customer classes. The NBEUB approved EGNB s request on May 25, 2011 and, on July 14, 2011, the NBEUB approved increases to the natural gas distribution rates for all other customer classes.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Cabin Gas Plant Development

In October 2011, the Company announced it reached agreement with Encana Corporation, on behalf of certain co-owners of the Cabin Gas Plant Development (Cabin), whereby Enbridge will become the majority owner in the development located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. Under the terms of the Asset Purchase and Sale agreement, Enbridge will acquire a 57.7% interest in phases 1 and 2 of Cabin which together will be capable of processing 800 million cubic feet per day (mmcf/d) of natural gas.

Phase 1 of the development will have 400 mmcf/d of natural gas processing capacity. The plant is currently under construction and is expected to be in-service in the third quarter of 2012. Phase 2 will add an additional 400 mmcf/d of capacity and has been sanctioned by the producers and received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. Horn River producers can request the Company to expand Cabin up to an additional four phases.

On November 2, 2011, the Company announced it had reached agreement to acquire an additional interest in Cabin, increasing Enbridge s ownership interest to 71.0%. Upon completion of phases 1 and 2, the Company s total investment is expected to be approximately $1.1 billion.

Venice Gas Processing Facility

In January 2011, the Company announced plans for an estimated US$0.2 billion expansion of the condensate processing capacity of its Venice, Louisiana facility within its Offshore segment. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned 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 where it will be processed to separate and stabilize the condensate. The expansion, which will 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 the last quarter of 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-deepwater 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 (bcf/d). WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in March 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-deepwater 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 and it is expected to be in service in 2014.

Tioga Lateral Pipeline

In September 2011, Alliance Pipeline US announced 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. 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 and Hess have reached a concurrent agreement for the provision of natural gas liquids (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 120 mmcf/d, which can be expanded based on shipper demand. Subject to regulatory and other required approvals, the pipeline is expected to be in service by the third quarter of 2013.

Prairie Rose Pipeline

In July 2011, an affiliate of Aux Sable acquired the Palermo Conditioning Plant (previously known as the Stanley Condensate Recovery Plant) and the Prairie Rose Pipeline for US$0.2 billion. The Palermo Conditioning Plant removes condensate and will have a capacity of 80 mmcf/d. The 12-inch diameter, 134-kilometre (83-mile) Prairie Rose Pipeline, with an estimated capacity of 110 mmcf/d, connects the plant to the Alliance Pipeline, which then delivers high energy content gas to Aux Sable s Channahon, Illinois plant for further processing. Enbridge has a 42.7% equity interest in Aux Sable and a 50% interest in Alliance Pipeline US.

Greenwich Wind Energy Project

In October 2011, the Company completed development of the 99-megawatt (MW) Greenwich Wind Energy Project on the northern shore of Lake Superior in Ontario with Renewable Energy Systems Canada Inc. (RES Canada) at a cost of approximately $0.3 billion. Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada constructed the project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens will provide ongoing operations and maintenance services. The Greenwich Wind Energy Project will deliver energy to the Ontario Power Authority (OPA) under a 20-year power purchase agreement.

Cedar Point Wind Energy Project

Enbridge completed development of the 250-MW Cedar Point Wind Energy Project near Denver, Colorado with Renewable Energy Systems America Inc. (RES Americas) in September 2011 at a total cost of approximately US$0.5 billion. RES Americas constructed the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project is comprised of 139 Vestas V90 1.8-MW wind turbines on 20,000 acres of leased private land. Commercial operation began in November 2011 with the Cedar Point Wind Energy Project delivering electricity into the Public Service Company of Colorado grid under a 20-year, fixed price power purchase agreement.

Amherstburg and Tilbury Solar Projects

The Company has developed two solar energy projects totaling 20-MW at a cost of approximately $0.1 billion. The 5-MW Tilbury Solar Project, completed in December 2010, is located in Tilbury, Ontario. The Amherstburg II Solar Project, located in Amherstburg, Ontario, consists of both a 10-MW facility and a 5-MW facility. First Solar constructed the projects for Enbridge under fixed price engineering, procurement and construction contracts. The Amherstburg II Solar Project was completed in the third quarter of 2011. Power output from the facilities is sold to the OPA pursuant to 20-year power purchase agreements.

Talbot Wind Energy Project

In June 2011, the Company acquired from RES Canada the remaining 10% interest in Talbot Windfarm, LP for $28 million, increasing its ownership to 100%. Ownership of the Talbot Wind Energy Project was subsequently restructured through a transfer to the Enbridge Income Fund (the Fund). See *Recent Developments Sponsored Investments Enbridge Income Fund Renewable Energy Assets Transfer*.

Lac Alfred Wind Project

On November 3, 2011, Enbridge announced agreement with EDF EN Canada Inc. under which Enbridge will invest approximately $0.3 billion to acquire a 50% interest in and become co-owner of the 300-megawatt (MW) Lac Alfred Wind Project. The project, located 400 kilometres (250 miles) northeast of Quebec City in Quebec s Bas-Saint-Laurent region, will consist of 150 wind turbines. Construction will be completed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1, which began in June 2011, 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 power purchase agreement and will construct the 30-kilometre transmission line to connect the Lac Alfred Wind Project to the grid under an interconnection agreement.

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 will increase takeaway capacity from the Bakken area by an initial 145,000 bpd, with further expansion available to increase takeaway capacity to 325,000 bpd. The Bakken Expansion Program will involve 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. In Canada, NEB hearings were concluded in October 2011. Subject to final NEB approval 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.

Allison Cryogenic Processing Plant

In April 2010, EEP announced plans to construct a cryogenic processing plant and other facilities on its Anadarko System. The Allison Plant will have a planned capacity of 150 mmcf/d and is intended to accommodate the acceleration of horizontal drilling activity that exists in the Granite Wash formation in the Texas Panhandle, where the Anadarko System is located. The Allison Plant is anticipated to be in service prior to the end of 2011.

South Haynesville Shale Expansion

In April 2011, EEP announced plans to invest an additional US$0.2 billion to expand its East Texas system. 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.

Cushing Terminal Storage Expansion Projects

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.2 million barrels. The total estimated cost of the expansion is approximately US$0.1 billion, with the new tanks expected to come into service throughout 2012.

Eastern Market Expansion

In October 2011, Enbridge and EEP announced two projects that will 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. The 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 total cost of approximately $0.1 billion. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of Line 9 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, both projects are expected to be in service in late 2012.

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. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. The Allison and Ajax plants, when operational, are expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

Texas Express Pipeline

In September 2011, EEP announced a joint venture with Enterprise and Anadarko Petroleum Corporation 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 Texas Express Pipeline (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 will have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. 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; the second will connect TEP to central Texas, Barnett Shale processing plants. Subject to regulatory approvals, the pipeline and portions of the gathering systems are expected to begin service in the second quarter of 2013.

Bakken Access Program

In October 2011, EEP announced the Bakken Access Program, a series of projects totaling approximately US$0.1 billion, which represents an upstream expansion that will further complement its 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, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

Two-for-One Stock Split

In April 2011, EEP announced the completion of a two-for-one split of its Common Units and i-Units. The two-for-one split was effected by a distribution of one unit for each unit outstanding and held by holders of record on April 7, 2011. Enbridge Energy Management, L.L.C. (EEM) also announced the completion of a two-for-one split of its listed shares and voting shares.

Enbridge Income Fund

Renewable Energy Assets Transfer

In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for an aggregate price of $1.2 billion. The transaction was financed by the Fund through a combination of debt and equity, including the issuance of additional ordinary trust units of the Fund (Units) to both Enbridge Income Fund Holdings Inc. (ENF) and Enbridge. Enbridge s overall economic interest in the Fund was reduced from 72% to 69% upon completion of the transaction and associated financing.

CORPORATE

Montana-Alberta Tie-Line

In October 2011, Enbridge announced the acquisition of all outstanding common shares of Tonbridge Power Inc. (Tonbridge) for $20 million. Enbridge repaid approximately $50 million of debt incurred by Tonbridge in the development of the Montana-Alberta Tie-Line (MATL) project and will also inject further funding to complete the first 300-MW phase of MATL, as well as an expansion to 550-MW. The total expected cost to complete both phases of MATL is approximately $0.3 billion, of which approximately half is being funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy.

The MATL project is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of growing supply of electric power in Montana and the buoyant power demand in Alberta. Required permits for the first phase of MATL have been obtained and the project has secured long-term, take-or-pay contracts for the system s entire initial northbound capacity, with in-service expected in mid-2012.

Neal Hot Springs Geothermal Project

The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project is anticipated to be completed in the second quarter of 2012 and will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Construction on the project has commenced and Enbridge will invest up to approximately $24 million for a 20% interest in the project.

Noverco

Enbridge s investment of $144 million to acquire an additional interest in Noverco Inc. (Noverco), announced in February 2011, was completed on June 30, 2011. Following the investment, Enbridge holds a 38.9% interest in Noverco, with the balance held by Trencap, a partnership controlled and managed by the Caisse de Depot et Placement due Quebec. Noverco is a holding company that owns approximately 71% of Gaz Metro Limited Partnership, a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the State of Vermont.

Preferred Share Issuance

On September 30, 2011, the Company issued Series B Preferred Shares for gross proceeds of $500 million. The twenty million 4.0% Cumulative Redeemable Preferred Shares, Series B are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25 per share plus all accrued and unpaid dividends, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series B Preferred Shares will have the right to convert their shares into Cumulative Redeemable Preferred Shares, Series C, subject to certain conditions, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series C Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.40%.

Two-for-One Stock Split

A two-for-one stock split was approved by shareholders of the Company at the May 2011 Annual and Special Meeting of Shareholders. Effective May 25, 2011, the number of outstanding shares doubled from approximately 387 million to approximately 774 million.

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

Enbridge holds an approximate 23.8% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Crude Oil Release

As a result of EEP s response to recent additional work direction from the Environmental Protection Agency (EPA), additional information concerning the reassessment of the overall monitoring area, related clean up, including submerged oil recovery operations, and remediation activities, EEP has revised its total estimate for costs related to the crude oil release on Line 6B of its Lakehead System to US$725 million ($123 million after-tax net to Enbridge), before insurance recoveries, as of September 30, 2011, an increase of US$140 million ($21 million after-tax net to Enbridge) from June 30, 2011. The US$140 million increase includes estimated costs related to the additional scope of work set forth in EEP s response to an EPA directive that was submitted to the EPA on October 20, 2011. EEP continues to make progress on the clean up, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at September 30, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. 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 as well as 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 for any additional requirements. The clean up, remediation and restoration of the areas affected by the release has been substantially completed. EEP s cost estimate in connection with this crude oil release remains at approximately US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential to incur 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

The Company maintains 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 increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates are likely to exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$85 million ($13 million after-tax net to Enbridge) and US$135 million ($21 million after-tax net to Enbridge) of insurance recoveries in the three and nine months ended September 30, 2011, respectively, for claims filed in connection with the Line 6B crude oil release, all of which have been received. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period that it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

Line 6B Pipeline Integrity Plan

In connection with the restart of Line 6B, EEP committed to accelerate a process, initiated prior to the crude oil release, to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA), EEP completed remediation of those pipeline anomalies it identified between 2007 and 2009 that were scheduled for refurbishment, and anomalies identified for action in a July 2010 PHMSA notification, on schedule within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, EEP also agreed to replace a 3,600 foot section of the Line

6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In February 2011, EEP filed a tariff supplement with the Federal Energy Regulatory Commission (FERC), which became effective on April 1, 2011, for recovery of US$175 million of capital costs and US$5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes, will be recovered over a 30-year period, while operating costs will be recovered through EEP s annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

Line Replacement Program

In May 2011, EEP announced plans to replace 120 kilometres (75 miles) of non-contiguous sections of Line 6B of its Lakehead System at an estimated cost of US$286 million. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and 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. EEP subsequently revised the scope of this project to increase the cost by approximately US$30 million, which will bring the total capital for this replacement program to an estimated cost of US$316 million. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

The pipeline integrity and replacement costs will be capitalized or expensed in accordance with EEP s capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

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. Currently, 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. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at September 30, 2011. 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.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Canadian Mainline	**102**	81	**265**	243
Regional Oil Sands System	**27**	20	**80**	58
Southern Lights Pipeline	**18**	17	**54**	62
Spearhead Pipeline	**4**	8	**14**	23
Feeder Pipelines and Other	**(1)**	2	**(3)**	9
Adjusted earnings	**150**	128	**410**	395
Canadian Mainline - shipper dispute settlement	**-**	-	**14**	-
Canadian Mainline - Line 9 tolling adjustment	**(3)**	-	**10**	-
Canadian Mainline - unrealized derivative fair value loss	**(180)**	-	**(134)**	-
Spearhead Pipeline - unrealized derivative fair value gains	**1**	-	**1**	-
Feeder Pipelines and Other - unrealized derivative fair value gains	**1**	-	**1**	-
Earnings/(loss)	**(31)**	128	**302**	395

Liquids Pipelines adjusted earnings for the three months ended September 30, 2011 were $150 million compared with $128 million for the three months ended September 30, 2010. Adjusted earnings for the nine months ended September 30, 2011 were $410 million, an increase of $15 million compared with adjusted earnings of $395 million in the prior year comparable period. The Company continued to realize earnings growth on the Canadian Mainline and the Regional Oil Sands System; however, such growth was partially offset by lower contributions from its Southern Lights and Spearhead pipelines, as well as Feeder Pipelines and Other.

Effective July 1, 2011, Canadian Mainline earnings are governed by the CTS (with the exception of Lines 8 and 9) whereas earnings for the first six months of 2011 and for the year ended December 31, 2010 were governed by a series of agreements, the most significant being the ITS applicable to the mainline system and the Terrace and Alberta Clipper agreements. Under the terms of the CTS, the initial Canadian local toll is based on the 2011 ITS toll and will be subsequently adjusted by 75% of the Canada Gross Domestic Product at Market Price Index, effective July 1st, for each of the remaining nine years of the settlement. The CTS also provides for an IJT for crude oil shipments originating in Canada on the mainline system and delivered in the United States off the Lakehead System and into eastern Canada. Earnings under the CTS are subject to variability in volume throughput and operating costs. The variance in earnings for both the three and nine months ended September 30, 2011 compared with the corresponding periods of the prior year primarily reflected this change in the Company s underlying commercial arrangements with shippers. Also, Canadian Mainline earnings for the nine months ended September 30, 2011 included in-service earnings from Alberta Clipper compared with allowance for equity funds used during construction (AEDC) recognized while the project was under construction until its in-service date of April 1, 2010.

Supplemental information on Canadian Mainline adjusted earnings for the third quarter of 2011, the first full quarter of operations under the CTS, is as follows.

15

(millions of Canadian dollars, unless otherwise noted)	**Three months ended September 30, 2011**
Revenues	**314**
Expenses	
Operating and administrative	**87**
Power	**28**
Depreciation and amortization	**53**
	168
	146
Other income	**3**
Interest expense	**(32)**
	117
Income taxes	**(15)**
Adjusted earnings	**102**
IJT Benchmark Toll[1] *(United States dollars per barrel)*	**$3.85**
Lakehead System Local Toll[2] *(United States dollars per barrel)*	**$2.01**
Canadian Mainline IJT Residual Benchmark Toll[3] *(United States dollars per barrel)*	**$1.84**
Effective United States dollar to Canadian dollar exchange rate[4]	**0.99**

1 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.

2 Per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois.

3 Per barrel of heavy crude oil transported from Hardisty to Gretna. The Canadian Mainline IJT residual toll for any shipment is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.

4 Inclusive of realized gains or losses on foreign exchange derivative financial instruments.

	2011				2010			
	Q3	Q2	Q1		Q4	Q3	Q2	Q1
Throughput volume[1] *(kbpd)*	**1,564**	1,459	1,605		1,537	1,468	1,629	1,515

1 Throughput volume, presented in thousands of barrels per day (kbpd), represents mainline deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.

Canadian Mainline revenues include the portion of the system covered by the CTS as well as revenues from Line 8 and Line 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 charges, the largest component, as well as allowance oil and terminaling receipt and delivery charges. Transportation charges include charges for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which IJT residual tolls apply, and volumes delivered to other western Canada delivery points, to which Canadian local tolls apply. Despite the many factors which affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the IJT United States dollar residual benchmark toll applicable to most of those volumes, and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. 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. Canadian Mainline revenues for the third quarter were stronger than expected primarily due to higher than anticipated throughput volume ex-Gretna.

Operating and administrative expenses for the three months ended September 30, 2011 were $87 million, the largest components being 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 operating costs are expected to be normal escalation in wage rates, prices for purchased services and tax rates, 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.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and of additions to property, plant and equipment due to new facilities, as well as maintenance and integrity capital expenditures.

Canadian Mainline income taxes for the three months ended September 30, 2011 were $15 million and reflected current income taxes only. As under the CTS the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment, an offsetting regulatory asset related to future 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 on July 1, 2011, 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 on a prospective basis commencing July 1, 2011. 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 no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset related to future income taxes recorded at the date of discontinuance of approximately $470 million will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. Canadian Mainline property, plant and equipment balances will continue to be recognized at historic cost subject to normal course impairment assessment.

Regional Oil Sands System earnings increased as a result of higher shipped volumes and increased tolls on certain laterals, as well as an increased contribution from Hardisty Caverns Limited Partnership which is now wholly-owned by the Company. Another factor which contributed to the increase was lower depreciation expense due to extended estimated useful lives of certain assets reflecting increased probable reservoir supply and commercial viability.

The decrease in Southern Lights Pipeline year-to-date earnings primarily reflected a decrease in leasing income from a pipeline which was transferred to the mainline system effective May 1, 2010. Both the Canadian and United States portions of the tariff for uncommitted shippers on the Southern Lights Pipeline have been challenged. Accordingly, a FERC hearing process was initiated and a hearing has been scheduled for January 10, 2012. The Canadian Southern Lights toll hearing has been set by the NEB for November 15, 2011. No material financial impacts to the Company are anticipated from either of these proceedings.

The decrease in Spearhead Pipeline earnings primarily reflected lower throughput volumes as a result of current market pricing dynamics at Cushing, Oklahoma.

The decrease in Feeder Pipelines and Other earnings was primarily due to an increase in business development costs.

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 for 2011 included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2011 reflected unrealized fair value losses on derivative financial instruments used to risk manage exposures inherent within the CTS agreement, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Spearhead Pipeline earnings included unrealized fair value gains on derivative financial instruments related to allowance oil commodity prices.
- Feeder Pipelines and Other loss included unrealized fair value gains on derivative financial instruments related to allowance oil commodity prices.

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Gas Distribution (EGD)	**(9)**	(9)	**100**	89
Other Gas Distribution and Storage	**7**	4	**29**	24
Adjusted earnings/(loss)	**(2)**	(5)	**129**	113
EGD - (warmer)/colder than normal weather	**-**	-	**13**	(18)
Earnings/(loss)	**(2)**	(5)	**142**	95

Adjusted loss from Gas Distribution was $2 million for the three months ended September 30, 2011 compared with a loss of $5 million for the three months ended September 30, 2010. Adjusted earnings from Gas Distribution were $129 million and $113 million for the nine months ended September 30, 2011 and 2010, respectively.

The increase in EGD s adjusted earnings for the first nine months of 2011 was primarily due to favourable operating performance including the timing of certain expenditures. Positive earnings contributions included customer growth and lower interest expense, partially offset by higher system integrity costs, higher depreciation expense and lower variable charges to customers. The progressive substitution of lower per unit volumetric charges to customers with corresponding increases in fixed charges modifies EGD s quarterly earnings profile relative to the prior year, but does not materially impact full year earnings as earnings are shifted from the colder winter months to the warmer summer months.

The earnings increase in Other Gas Distribution and Storage reflected higher contributions from Enbridge s Ontario unregulated gas storage business and from customer growth at EGNB.

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.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Offshore Pipelines (Offshore)	**(4)**	7	**(5)**	21
Alliance Pipeline US	**6**	6	**19**	19
Vector Pipeline	**4**	3	**13**	11
Aux Sable	**12**	11	**36**	27
Energy Services	**16**	5	**42**	14
Other	**5**	(1)	**17**	-
Adjusted Earnings	**39**	31	**122**	92
Offshore - property insurance recoveries from hurricanes	**-**	-	**-**	2
Aux Sable - unrealized derivative fair value gains/(loss)	**4**	(9)	**(3)**	5
Energy Services - unrealized derivative fair value gains/(loss)	**8**	(3)	**17**	(11)
Energy Services - Lehman credit recovery	**-**	-	**-**	1
Earnings	**51**	19	**136**	89

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $39 million and $122 million for the three and nine months ended September 30, 2011, respectively, compared with $31 million and $92 million for the three and nine months ended September 30, 2010. The increase was primarily due to higher adjusted earnings in Aux Sable, Energy Services and Other, partially offset by losses in Offshore.

The decrease in Offshore adjusted earnings was primarily due to volume declines including natural production declines in existing reserves. The slower regulatory permitting process has impacted the level and timing of drilling activity in the Gulf of Mexico and the resultant production volumes available to ship on the Company s Offshore system. Higher operating and administrative costs and depreciation expense also contributed to the decrease in adjusted earnings in both the three and nine-month periods ended September 30, 2011 compared with the corresponding periods of 2010. Offshore adjusted earnings for the nine months ended September 30, 2010 included $2 million in insurance proceeds related to reimbursement for business interruption lost revenues and operating expenses associated with a hurricane in 2008.

Aux Sable adjusted earnings increased primarily due to stronger realized fractionation margins which resulted in higher contributions from the upside sharing mechanism in its production sales agreement.

Energy Services includes the Company s energy marketing businesses which provide a range of crude oil, natural gas and NGL marketing services including transportation, storage and supply management. For the three and nine months ended September 30, 2011, Energy Services earnings were $16 million and $42 million, respectively, representing increases of $11 million and $28 million over the corresponding periods of 2010. These increases were primarily attributable to crude oil marketing strategies designed to capture location differential and tank management revenue when opportunities arise. Energy Services employs such strategies in compliance with and under the oversight of the Company s formal risk management policies and procedures. Partially offsetting positive earnings contributions from crude oil services were declines in natural gas marketing due to narrower natural gas location basis spreads, which impact the Company s merchant capacity on certain natural gas pipelines. Earnings from Energy Services are dependent on market conditions, including, but not limited to commodity prices and location and grade basis spreads, and may not be indicative of results to be achieved in future periods.

19

Other adjusted earnings totaled $17 million for the first nine months of 2011 and reflected strong contributions from the Sarnia Solar expansion and Talbot Wind Energy Project, both of which were completed in the latter part of 2010. Subsequent to September 30, 2011, ownership of the Enbridge Ontario Wind, Sarnia Solar and Talbot Wind energy projects was transferred to the Fund. Effective October 21, 2011, earnings contributions from these assets, net of noncontrolling interest, will be reflected within the Sponsored Investments segment.

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

- Offshore earnings for the nine months ended September 30, 2010 included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.
- 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 inventory and the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions.
- Energy Services earnings for 2010 included a partial recovery of $1 million from the sale of its receivable from Lehman Brothers.

SPONSORED INVESTMENTS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Energy Partners (EEP)	**41**	34	**106**	95
Enbridge Energy, L.P. - Alberta Clipper US (EELP)	**10**	14	**32**	32
Enbridge Income Fund (the Fund)	**12**	11	**37**	34
Adjusted earnings	**63**	59	**175**	161
EEP - leak insurance recoveries	**13**	-	**21**	-
EEP - leak remediation costs and lost revenue	**(21)**	(85)	**(27)**	(85)
EEP - unrealized derivative fair value gains/(loss)	**8**	(3)	**8**	2
EEP - shipper dispute settlement	**-**	-	**8**	-
EEP - lawsuit settlement	**-**	-	**1**	-
EEP - impact of unusual weather conditions	**-**	-	**(1)**	-
EEP - Lakehead System billing correction	**-**	-	**-**	1
EEP - dilution gain on Class A unit issuance	**-**	3	**-**	4
EEP - asset impairment loss	**-**	(2)	**-**	(2)
Earnings/(loss)	**63**	(28)	**185**	81

Sponsored Investments adjusted earnings were $63 million for the three months ended September 30, 2011 compared with $59 million for the three months ended September 30, 2010. For the nine months ended September 30, 2011, adjusted earnings were $175 million compared with $161 million in the comparable prior period.

EEP adjusted earnings were $106 million for the nine months ended September 30, 2011 compared with $95 million for the nine months ended September 30, 2010. The increase was largely attributable to the natural gas business and higher incentive income. Increased earnings in the natural gas business were due to increased natural gas and NGL volumes, including those associated with the acquisition of the Elk City System in September 2010, partially offset by an increase in operating and administrative costs, depreciation expense and higher financing costs incurred as a result of additional assets placed in service during 2010. Earnings for the first nine months of 2011 also included in-service earnings from Alberta Clipper compared with AEDC recognized while the project was under construction until its in-service date of April 1, 2010.

EELP earnings represent the Company s earnings from its 66.7% investment in a series of equity securities issued by EELP which owns the United States segment of the Alberta Clipper Project. In the third quarter of 2010, earnings were favourably impacted by lower operating costs, predominately property tax rates applicable during the construction phase relative to the deemed recovery permitted in tolls.

Earnings for the Fund totaled $37 million for the first nine months of 2011 and reflected increased contributions from the Saskatchewan System following substantial completion of its Phase II expansion project in December 2010, partially offset by additional financing costs.

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

- EEP 2011 earnings included insurance recoveries associated with the Line 6B crude oil release. *See Recent Developments - EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

- EEP earnings included a charge in each period related to estimated costs, before insurance recoveries, associated with the Line 6B and 6A crude oil releases. EEP earnings for 2010 also included a charge of $3 million (net to Enbridge) related to lost revenue as a result of the crude oil releases. *See Recent Developments - EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

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

- EEP earnings for 2011 included proceeds of $8 million (net to Enbridge) from the settlement of a shipper dispute related to oil measurement adjustments in prior years.

- EEP earnings for 2011 included proceeds related to the settlement of a lawsuit during the first quarter.

- EEP earnings for 2011 included an unfavourable effect of $1 million (net to Enbridge) related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations.

- EEP earnings for 2010 included Lakehead System billing corrections.

- EEP earnings for 2010 included dilution gains (after tax and noncontrolling interest).

- EEP earnings for 2010 included charges related to asset impairment losses.

CORPORATE

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Noverco	**(3)**	(4)	**14**	13
Other Corporate	**(6)**	(13)	**(15)**	(28)

Adjusted loss	**(9)**	(17)	**(1)**	(15)
Corporate - unrealized derivative fair value gains/(loss)	**(83)**	39	**(132)**	(23)
Corporate - unrealized foreign exchange gains on translation of intercompany balances, net	**6**	21	**23**	15
Corporate - impact of tax rate changes	**9**	-	**1**	-
Earnings/(loss)	**(77)**	43	**(109)**	(23)

Total Corporate adjusted loss was $9 million and $1 million for the three and nine months ended September 30, 2011, respectively, compared with an adjusted loss of $17 million and $15 million for the three and nine months ended September 30, 2010.

Other Corporate adjusted loss for the third quarter decreased primarily as a result of lower financing costs.

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

- Earnings/(loss) for each period included a change in the unrealized fair value gains and losses on derivative financial instruments related to forward foreign exchange risk management positions.

- Earnings/(loss) included net unrealized foreign exchange gains 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 replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common share dividends. At September 30, 2011, excluding the Southern Lights project financing, the Company had $6,518 million of committed credit facilities of which $2,911 million was drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $449 million, the Company had net available liquidity at September 30, 2011 of $4,056 million. The net available liquidity, along with expected future access to public and 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 optimize pricing and other terms. The following table provides details of the Company s credit facilities at September 30, 2011.

	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	300	26	274
Gas Distribution	2011-2013	718	439	279
Sponsored Investments	2013	500	204	296
Corporate[4]	2012-2016	5,000	2,242	2,758
		6,518	2,911	3,607
Southern Lights project financing[1]	2012-2014	1,624	1,502	122
Total credit facilities		8,142	4,413	3,729

1 *Total facilities inclusive of $62 million for debt service reserve letters of credit.*

2 *Total facilities includes $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.*

4 *In October 2011, the Company secured additional revolving facilities of US$500 million with a maturity date of 2013.*

OPERATING ACTIVITIES

Cash provided from operating activities was $719 million and $2,251 million for the three and nine months ended September 30, 2011, respectively, compared with $319 million and $1,476 million for the three and nine months ended September 30, 2010. Cash from operating activities was positively impacted in 2011 by favourable operating performance, primarily in Regional Oil Sands System, Energy Services and the Company s green energy assets, as well as the impact of colder weather within the EGD franchise area. Also contributing to the change in cash from operating activities was an increase in cash distributions from the Company s investments in Noverco and in EELP, which owns the United States segment of Alberta Clipper, as well as variations in working capital requirements.

There are no material restrictions on the Company s cash with the exception of proportionately consolidated joint venture cash of $126 million, which cannot be accessed until distributed to the Company, restricted cash of $5 million related to Southern Lights project financing and cash in trust of $4 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three and nine months ended September 30, 2011 was $751 million and $1,838 million, respectively, compared with $741 million and $1,928 million for the three and nine months ended September 30, 2010. Cash used in investing activities included $701 million (2010 - $698 million) and $1,514 million (2010 - $1,563 million) of additions to property, plant and equipment for the three and nine months ended September 30, 2011, respectively, largely directed towards the Company s growth projects. In June 2011, the Company acquired an additional interest in Noverco for $144 million and also acquired the remaining 10% interest in the Talbot Wind Energy Project for $28 million. Investing activities for the nine months ended September 30, 2010 included a use of cash related to long-term investments and affiliate lending, primarily the Company s investing in and funding of EELP while the Alberta Clipper Project was under construction.

FINANCING ACTIVITIES

Cash used in financing activities totaled $89 million for the nine months ended September 30, 2011 compared with a source of cash of $597 million in the corresponding period of 2010. During the first three quarters of 2011, the Company issued debentures and term notes totaling $450 million which in part funded net repayments of short-term sources totaling $418 million. Year-to-date financing activities at September 30, 2011 also included a term note repayment of $150 million. In comparison, term note issuances of $1,800 million were completed in the nine months ended September 30, 2010, which in part funded debt repayments totaling $919 million. The Company also repaid $50 million of its Southern Lights project financing facility in the first nine months of 2011, compared with a net draw of $22 million in the corresponding period of 2010. On September 30, 2011, the Company completed a public offering of Preferred Shares, resulting in a source of cash of $488 million which will be used for capital expenditures, to repay indebtedness and for other general corporate purposes.

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended September 30, 2011, dividends declared were $191 million (2010 - $163 million), of which $127 million (2010 - $107 million) were paid in cash and reflected in financing activities. The remaining $64 million (2010 - $56 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the nine months ended September 30, 2011, dividends declared were $569 million (2010 - $485 million), of which $387 million (2010 - $316 million) were paid in cash and reflected in financing activities. The remaining $182 million (2010 - $169 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and nine months ended September 30, 2011, 34% (2010 - 34%) and 32% (2010 - 35%) of total dividends declared were reinvested.

On October 28, 2011, the Enbridge Board of Directors declared quarterly dividends of $0.245 per common share and $0.34375 per Series A Preferred Share. Both dividends are payable on December 1, 2011 to shareholders of record on November 15, 2011.

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials totaling $2,086 million which are expected to be paid within the next five years and thereafter.

QUARTERLY FINANCIAL INFORMATION[1]

		2011			2010			2009
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
(millions of Canadian dollars, except per share amounts)								
Revenues	**4,272**	4,981	4,713	4,143	3,502	3,505	3,977	3,187
Earnings attributable to common shareholders	**4**	259	393	326	157	138	342	300
Earnings per common share[2]	**0.01**	0.35	0.52	0.44	0.21	0.19	0.47	0.40
Diluted earnings per common share[2]	**0.01**	0.34	0.52	0.43	0.21	0.18	0.46	0.40
Dividends per common share[2]	**0.2450**	0.2450	0.2450	0.2125	0.2125	0.2125	0.2125	0.1850
EGD - warmer/(colder) than normal weather	**-**	(2)	(11)	(6)	-	10	8	(3)
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**235**	27	(43)	(71)	(45)	87	(30)	(27)

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

2 *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 resultant 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 undertook a substantial capital program in recent years 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 *Recent Developments*.

In addition to the impacts of EGD weather and unrealized gains and losses outlined above, significant items that impacted the quarterly earnings were as set forth below.

- Third quarter 2011 earnings reflected stronger contributions from Canadian Mainline and Energy Services, partially offset by lower contributions from Offshore and an $8 million net charge to earnings related to the Line 6B crude oil release.

- Second quarter 2011 earnings reflected increased earnings from EGD due to favourable operating performance, as well as proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years within Liquids Pipelines and Sponsored Investments.

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

- Fourth quarter 2010 earnings reflected a dilution gain on reduced ownership in EEP, partially offset by additional leak remediation costs and the elimination of annual performance metrics under the Liquids Pipelines 2010 interim toll agreement.

- Reflected in earnings for the third and fourth quarters of 2010 are leak remediation costs and lost revenue associated with the Line 6B and Line 6A crude oil releases in the amounts of $85 million and $21 million, respectively.

- 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 those dates forward. Previous quarters include AEDC while the projects were under construction.

RISK MANAGEMENT

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 movements. In June 2011, the Company entered into additional derivative instruments to mitigate the volatility of short-term interest rates on interest expense through 2015 at an average rate of 2.42%.

At September 30, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in a $18 million increase (2010 - nil) in earnings and would have caused a $333 million increase (2010 - $310 million) in Other Comprehensive Income (OCI) due to the revaluation of interest rate derivatives outstanding at September 30, 2011, and a $20 million decrease (2010 - $23 million) in earnings due to increased interest expense related to the Company s variable rate debt outstanding at September 30, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Earnings for the nine months ended September 30, 2011 included a loss of $4 million (2010 - nil) as a result of ineffectiveness on interest rate derivatives used as cash flow hedges.

Foreign Exchange and Commodity Price Risk

As a result of renegotiations with shippers on certain pipelines, the Company is now exposed to additional foreign exchange rate risk on United States dollar denominated revenues and additional commodity price risk resulting from increased exposure to variable crude oil and power prices.

The Company s earnings, cash flows and OCI are subject to foreign exchange variability, primarily arising from its United States dollar denominated investments, subsidiaries and certain revenues denominated in United States dollars. In June 2011, the Company entered into additional derivative instruments to mitigate cash flow volatility due to the effect of future foreign exchange rate fluctuations, including the collection of tolls on the Canadian Mainline in United States dollars pursuant to the CTS agreement. Specifically, for the years ending December 31, 2011 through 2015, the Company has entered into instruments to mitigate between 80% and 90% of this exposure at United States to Canadian dollar foreign exchange rates of $0.96, $0.97, $1.00, $1.02 and $1.03 (all expressed as Canadian dollars per United States dollar), respectively. These derivative instruments are classified as non-qualifying with changes in fair value recognized in Transportation and other services revenues.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at September 30, 2011 would have resulted in a $248 million increase to earnings (2010 - $72 million) due to the revaluation of foreign exchange derivative instruments. Such a strengthening, if sustained, would reduce the Canadian dollar equivalent of United States dollar earnings streams by more than $248 million as the United States dollar earnings streams are not fully hedged. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company s United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

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. During the nine months ended September 30, 2011, the Company entered into additional power swap and crude oil derivative instruments to fix a portion of the variable price exposures arising from operating costs associated with certain transportation agreements. These derivative instruments are classified as non-qualifying with changes in fair value recognized in Transportation and other services revenues, as well as in Operating and administrative expenses.

The Company has defined Earnings at Risk (EaR) limits for different components of businesses exposed to commodity price risk. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. For the nine months ended September 30, 2011 and 2010, the Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from total commodity price risk over a one month period.

(millions of Canadian dollars)	**2011**	2010
Average EaR during the year	**23**	21
High EaR during the year	**27**	25
Low EaR during the year	**18**	16
Closing EaR at quarter end	**21**	25

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

	September 30, 2011		December 31, 2010	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards - purchase *(millions of United States dollars)*	**2011-2020**	**1,211**	2011-2020	1,185
U.S. dollar forwards - sell *(millions of United States dollars)*	**2011-2020**	**8,870**	2011-2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	**2011-2029**	**14,199**	2011-2029	10,772
Commodity contracts - energy *(billions of cubic feet equivalent)*	**2011-2013**	**38**	2011-2013	41
Commodity contracts - power *(megawatts per hour)*	**2011-2024**	**54**	2011-2024	2

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 setting aside funds for abandonment 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.

The NEB is requiring both Group 1 and Group 2 companies to file for approval estimates of abandonment costs by November 30, 2011. The NEB is also requiring large pipeline companies to file a proposed process for collecting and setting aside the funds for abandonment by November 30, 2012 for Group 1 companies (including Enbridge Pipelines Inc.) and by May 31, 2013 for Group 2 companies (including Southern Lights Pipeline).

Both of the required submissions will require NEB approval and will result in increases to transportation tolls, the amount of which is uncertain at this time. Currently, for certain of the Company s assets, it is not practical to make a reasonable estimate of asset retirement obligations for accounting purposes due to the indeterminate timing and the scope of the asset retirements.

CHANGES IN ACCOUNTING POLICIES

BUSINESS COMBINATIONS

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any existing equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard had no material impact to the Company s earnings or cash flows for the three or nine month period ended September 30, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements,* and 1602, *Noncontrolling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

FUTURE ACCOUNTING POLICIES

United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate-regulated operations of the Company, which are pervasive and central to its commercial environment and performance measurement. The Company does not expect a rate-regulated accounting standard to be finalized by the International Accounting Standards Board in advance of 2012. The Company believes U.S. GAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated businesses. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary financial statements. Management reports regularly to the Audit, Finance and Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

Accounting and Reporting

The Company has commenced integrating known U.S. GAAP differences into its primary financial statements. The most significant differences impact the following areas:

- Consolidation of EEP;
- Equity accounting treatment of joint ventures;

- Inventory valuation;
- Common control transactions;
- Classification and valuation of redeemable noncontrolling interests;
- Pensions and other post-employment benefits; and
- Presentation differences, including the presentation of deferred financing costs.

Under U.S. GAAP the Company is deemed to control EEP and will therefore consolidate its interest in the partnership.

The Company has substantially completed the preparation of model U.S. GAAP financial statements to identify the type of information and level of detail required to be disclosed under U.S. GAAP and has commenced the preparation of comparative financial statements under U.S. GAAP.

Training

As an SEC registrant, the Company has experience reporting under U.S. GAAP and has reconciled its financial statements to U.S. GAAP for many years. Further, two of the Company s affiliates, EEM and EEP are also registered with the SEC and currently prepare and file U.S. GAAP financial statements. The Company has a detailed plan to provide supplemental U.S. GAAP training to internal personnel impacted by the conversion. Training initiatives have commenced and will continue throughout 2011.

Information Systems and Business Processes

The Company has evaluated whether systems solutions are necessary to support the conversion to U.S. GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Testing and implementation of certain systems changes began in the third quarter of 2011 and is expected to continue throughout the fourth quarter. Related impacts to internal controls over financial reporting and disclosure controls and procedures will be identified and addressed over the remainder of 2011.

Business Activities

The Company has reviewed the effect of the U.S. GAAP conversion on its debt covenants, compensation agreements and hedging activities and does not expect the conversion to U.S. GAAP to significantly impact these activities or requirements.

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to the issuance of new accounting standards or amendments to existing accounting standards, changes in regulation or economic conditions or other factors.

NON-GAAP RECONCILIATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
GAAP earnings as reported	**4**	157	**656**	637
Significant after-tax non-recurring or non-operating factors and variances:				
Liquids Pipelines				
Canadian Mainline - shipper dispute settlement	**-**	-	**(14)**	-
Canadian Mainline - Line 9 tolling adjustment	**3**	-	**(10)**	-
Canadian Mainline - unrealized derivative fair value loss	**180**	-	**134**	-
Spearhead Pipeline - unrealized derivative fair value gains	**(1)**	-	**(1)**	-
Feeder Pipelines and Other - unrealized derivative fair value gains	**(1)**	-	**(1)**	-
Gas Distribution				
EGD - (colder)/warmer weather than normal	**-**	-	**(13)**	18
Gas Pipelines, Processing and Energy Services				
Offshore - property insurance recoveries from hurricanes	**-**	-	**-**	(2)
Aux Sable - unrealized derivative fair value (gains)/loss	**(4)**	9	**3**	(5)
Energy Services - unrealized derivative fair value (gains)/loss	**(8)**	3	**(17)**	11
Energy Services - Lehman credit recovery	**-**	-	**-**	(1)
Sponsored Investments				
EEP - leak insurance recoveries	**(13)**	-	**(21)**	-
EEP - leak remediation costs	**21**	85	**27**	85
EEP - unrealized derivative fair value (gains)/loss	**(8)**	3	**(8)**	(2)
EEP - shipper dispute settlement	**-**	-	**(8)**	-
EEP - lawsuit settlement	**-**	-	**(1)**	-
EEP - impact of unusual weather conditions	**-**	-	**1**	-
EEP - Lakehead System billing correction	**-**	-	**-**	(1)
EEP - dilution gain on Class A unit issuance	**-**	(3)	**-**	(4)
EEP - asset impairment loss	**-**	2	**-**	2
Corporate				
Unrealized derivative fair value (gains)/loss	**83**	(39)	**132**	23
Unrealized foreign exchange gains on translation of intercompany balances, net	**(6)**	(21)	**(23)**	(15)
Impact of tax rate changes	**(9)**	-	**(1)**	-
Adjusted earnings	**241**	196	**835**	746

OUTSTANDING SHARE DATA[1]

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Preferred Shares, Series B (non-voting equity shares)	20,000,000
Common Shares - issued and outstanding (voting equity shares)	779,202,455
Stock Options - issued and outstanding (18,520,225 vested)	32,767,773

1 *Outstanding share data information is provided as at October 31, 2011.*

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

September 30, 2011

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**3,601**	2,725	**11,544**	8,710
Transportation and other services	**671**	777	**2,422**	2,274
	4,272	3,502	**13,966**	10,984
Expenses				
Commodity costs	**3,417**	2,596	**10,931**	8,221
Operating and administrative	**417**	366	**1,141**	1,049
Depreciation and amortization	**236**	214	**692**	612
	4,070	3,176	**12,764**	9,882
	202	326	**1,202**	1,102
Income/(loss) from equity investments	**56**	(135)	**215**	22
Other income/(expense)	**(102)**	125	**12**	177
Interest expense	**(170)**	(185)	**(532)**	(508)
	(14)	131	**897**	793
Income taxes recovery/(expense)	**24**	(1)	**(212)**	(153)
Earnings	**10**	130	**685**	640
(Earnings)/loss attributable to noncontrolling interests	**(5)**	28	**(24)**	2
Earnings attributable to Enbridge Inc.	**5**	158	**661**	642
Preferred share dividends	**(1)**	(1)	**(5)**	(5)
Earnings attributable to Enbridge Inc. common shareholders	**4**	157	**656**	637
Earnings per common share attributable to Enbridge Inc. common shareholders	**0.01**	0.21	**0.87**	0.86
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	**0.01**	0.21	**0.86**	0.85

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars)				
Earnings	**10**	130	**685**	640
Other comprehensive loss				
Change in unrealized loss on cash flow hedges, net of tax	**(313)**	(54)	**(259)**	(166)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(104)**	35	**(63)**	3
Reclassification to earnings of realized cash flow hedges, net of tax	**11**	(57)	**1**	(26)
Other comprehensive loss from equity investees, net of tax	**(20)**	(11)	**(33)**	(24)
Change in foreign currency translation adjustment	**369**	(162)	**200**	(84)
Other comprehensive loss	**(57)**	(249)	**(154)**	(297)
Comprehensive income/(loss)	**(47)**	(119)	**531**	343
Comprehensive (income)/loss attributable to noncontrolling interests	**(26)**	47	**(27)**	26
Comprehensive income/(loss) attributable to Enbridge Inc.	**(73)**	(72)	**504**	369
Preferred share dividends	**(1)**	(1)	**(5)**	(5)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(74)**	(73)	**499**	364

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Nine months ended September 30,	
	2011	2010
(unaudited; millions of Canadian dollars, except per share amounts)		
Preferred shares		
Balance at beginning of period	**125**	125
Shares issued	**488**	-
Balance at end of period	**613**	125
Common shares		
Balance at beginning of period	**3,683**	3,379
Dividend reinvestment and share purchase plan	**182**	169
Shares issued on exercise of stock options	**36**	64
Balance at end of period	**3,901**	3,612
Contributed surplus		
Balance at beginning of period	**59**	54
Stock-based compensation	**15**	10
Options exercised	**(5)**	(5)
Dilution gains	**46**	-
Other	**(1)**	-
Balance at end of period	**114**	59
Retained earnings		
Balance at beginning of period	**4,734**	4,400
Earnings attributable to Enbridge Inc. common shareholders	**656**	637
Common share dividends declared	**(569)**	(485)
Dividends paid to reciprocal shareholder	**19**	14
Balance at end of period	**4,840**	4,566
Accumulated other comprehensive loss		
Balance at beginning of period	**(882)**	(543)
Other comprehensive loss	**(157)**	(273)
Balance at end of period	**(1,039)**	(816)
Reciprocal shareholding		
Balance at beginning of period	**(154)**	(154)
Acquisition of equity investment (*Note 4*)	**(33)**	-
Balance at end of period	**(187)**	(154)
Total Enbridge Inc. shareholders equity	**8,242**	7,392
Noncontrolling interests		
Balance at beginning of period	**658**	727
Earnings/(loss) attributable to noncontrolling interests	**24**	(2)
Other comprehensive income/(loss) attributable to noncontrolling interests		
Change in unrealized loss on cash flow hedges, net of tax	**(4)**	(10)
Other comprehensive loss from equity investees, net of tax	**(10)**	(8)
Change in foreign currency translation adjustment	**17**	(6)
	3	(24)
Comprehensive income/(loss) attributable to noncontrolling interests	**27**	(26)
Distributions, net	**(9)**	(6)
Acquisition (*Note 4*)	**(27)**	11
Dilution gains	**18**	-
Other	**2**	-
Balance at end of period	**669**	706
Total shareholders equity	**8,911**	8,098
Dividends paid per common share	**0.7350**	0.6375

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings attributable to Enbridge Inc.	**5**	158	**661**	642
Depreciation and amortization	**236**	214	**692**	612
Unrealized loss/(gain) on derivative instruments	**334**	(27)	**342**	56
Allowance for equity funds used during construction	**-**	(1)	**(2)**	(79)
Cash distributions in excess of equity earnings	**12**	209	**7**	152
Gain on reduction of ownership interest	**-**	(6)	**-**	(8)
Future income taxes	**48**	8	**191**	121
Noncontrolling interests	**5**	(28)	**24**	(2)
Other	**5**	(19)	**4**	1
Changes in regulatory assets and liabilities	**(11)**	16	**45**	45
Changes in operating assets and liabilities	**85**	(205)	**287**	(64)
	719	319	**2,251**	1,476
Investing activities				
Acquisition (*Note 4*)	**-**	(12)	**(28)**	(64)
Additions to property, plant and equipment	**(701)**	(698)	**(1,514)**	(1,563)
Additions to intangible assets	**(33)**	(21)	**(52)**	(38)
Change in construction payable	**(21)**	8	**(80)**	(78)
Long-term investments (*Note 4*)	**(7)**	(11)	**(174)**	(104)
Affiliate loans, net	**11**	(7)	**10**	(81)
	(751)	(741)	**(1,838)**	(1,928)
Financing activities				
Net change in short-term borrowings	**192**	282	**104**	(74)
Net change in commercial paper and credit facility draws	**(701)**	(248)	**(522)**	(341)
Debenture and term note issues	**450**	550	**450**	1,800
Debenture and term note repayments	**-**	-	**(150)**	(504)
Net change in Southern Lights project financing	**(10)**	(29)	**(50)**	22
Non-recourse debt issues	**-**	-	**9**	6
Non-recourse debt repayments	**(4)**	(3)	**(46)**	(38)
Contributions from/(distributions to) noncontrolling interests, net	**(5)**	17	**(9)**	(6)
Preferred shares issued	**488**	-	**488**	-
Common shares issued	**7**	29	**29**	53
Preferred share dividends	**(1)**	(1)	**(5)**	(5)
Common share dividends	**(127)**	(107)	**(387)**	(316)
	289	490	**(89)**	597
Effect of translation of foreign denominated cash and cash equivalents	**24**	(7)	**18**	(2)
Increase in cash and cash equivalents	**281**	61	**342**	143
Cash and cash equivalents at beginning of period	**303**	409	**242**	327
Cash and cash equivalents at end of period[1]	**584**	470	**584**	470
Supplementary cash flow information				
Income taxes paid/(received)	**(35)**	(14)	**(54)**	90
Interest paid	**155**	154	**533**	495

See accompanying notes to the unaudited consolidated financial statements.

1 Cash and cash equivalents consists of $343 million (2010 - $272 million) of cash and $241 million (2010 - $198 million) of short-term investments and includes restricted cash of $9 million (2010 - $11 million), and joint venture cash which is not readily accessible by the Company of $126 million (2010 - $108 million).

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited; millions of Canadian dollars)	**September 30, 2011**	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	**584**	242
Accounts receivable and other	**2,435**	2,706
Inventory	**762**	813
	3,781	3,761
Property, plant and equipment, net	**21,218**	20,332
Long-term investments	**2,487**	2,198
Deferred amounts and other assets	**2,936**	2,886
Intangible assets	**478**	478
Goodwill	**388**	385
Future income taxes	**42**	80
	31,330	30,120
Liabilities and shareholders equity		
Current liabilities		
Short-term borrowings	**430**	326
Accounts payable and other	**2,600**	2,688
Interest payable	**140**	117
Current maturities of long-term debt	**2**	154
Current maturities of non-recourse long-term debt	**94**	70
	3,266	3,355
Long-term debt	**13,550**	13,561
Non-recourse long-term debt	**1,016**	1,061
Other long-term liabilities	**2,034**	1,473
Future income taxes	**2,553**	2,447
	22,419	21,897
Shareholders equity		
Share capital		
Preferred shares	**613**	125
Common shares	**3,901**	3,683
Contributed surplus	**114**	59
Retained earnings	**4,840**	4,734
Accumulated other comprehensive loss	**(1,039)**	(882)
Reciprocal shareholding	**(187)**	(154)
Total Enbridge Inc. shareholders equity	**8,242**	7,565
Noncontrolling interests	**669**	658
	8,911	8,223
Commitments and contingencies *(Note 8)*		
	31,330	30,120

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with Part V - Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These interim consolidated financial statements do not include all disclosures required for annual financial statements and therefore should be read in conjunction with the consolidated financial statements and notes thereto included in the Company s 2010 Annual Report. These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company s consolidated financial statements are described in Note 10. Amounts are stated in Canadian dollars unless otherwise noted. These interim consolidated financial statements follow the same significant accounting policies and methods of application as those included in the 2010 Annual Report, except as described in Note 1.

Earnings for interim periods may not be indicative of results for the fiscal year due to the seasonal nature of the gas distribution utility business and other factors.

Certain comparative amounts have been reclassified to conform to the current period s presentation.

1. CHANGES IN ACCOUNTING POLICIES

Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any existing equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard had no material impact to the Company s earnings or cash flows for the three or nine month period ended September 30, 2011.

Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements,* and 1602, *Noncontrolling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

7

2. SEGMENTED INFORMATION

Three months ended September 30, 2011 *(unaudited; millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	**313**	**334**	**3,533**	**92**	**-**	**4,272**
Commodity costs	**-**	**(100)**	**(3,317)**	**-**	**-**	**(3,417)**
Operating and administrative	**(182)**	**(119)**	**(77)**	**(35)**	**(4)**	**(417)**
Depreciation and amortization	**(83)**	**(80)**	**(45)**	**(26)**	**(2)**	**(236)**
	48	**35**	**94**	**31**	**(6)**	**202**
Income/(loss) from equity investments	**-**	**-**	**-**	**73**	**(17)**	**56**
Other income/(expense)	**(46)**	**(1)**	**8**	**15**	**(78)**	**(102)**
Interest expense	**(63)**	**(40)**	**(25)**	**(16)**	**(26)**	**(170)**
Income taxes recovery/(expense)	**31**	**4**	**(26)**	**(36)**	**51**	**24**
Earnings	**(30)**	**(2)**	**51**	**67**	**(76)**	**10**
Earnings attributable to noncontrolling interests	**(1)**	**-**	**-**	**(4)**	**-**	**(5)**
Preferred share dividends	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Earnings attributable to Enbridge Inc. common shareholders	**(31)**	**(2)**	**51**	**63**	**(77)**	**4**
Additions to property, plant and equipment 1	**335**	**141**	**204**	**16**	**5**	**701**
Total assets	**12,135**	**7,393**	**5,784**	**4,053**	**1,965**	**31,330**

Three months ended September 30, 2010 *(unaudited; millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	456	329	2,636	81	-	3,502
Commodity costs	-	(90)	(2,506)	-	-	(2,596)
Operating and administrative	(157)	(120)	(54)	(30)	(5)	(366)
Depreciation and amortization	(77)	(77)	(35)	(22)	(3)	(214)
	222	42	41	29	(8)	326
Loss from equity investments	-	-	-	(127)	(8)	(135)
Other income	13	5	9	16	82	125
Interest expense	(67)	(49)	(22)	(13)	(34)	(185)
Income taxes recovery/(expense)	(39)	(1)	(9)	36	12	(1)
Earnings	129	(3)	19	(59)	44	130
(Earnings)/loss attributable to noncontrolling interests	(1)	(2)	-	31	-	28
Preferred share dividends	-	-	-	-	(1)	(1)
Earnings attributable to Enbridge Inc. common shareholders	128	(5)	19	(28)	43	157
Additions to property, plant and equipment 1	154	90	411	44	-	699
Total assets	11,420	3,848	6,007	7,231	588	29,094

1 Includes allowance for equity funds used during construction (AEDC)

Nine months ended September 30, 2011 *(unaudited; millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	**1,295**	**1,868**	**10,539**	**264**	**-**	**13,966**
Commodity costs	**-**	**(962)**	**(9,969)**	**-**	**-**	**(10,931)**
Operating and administrative	**(499)**	**(345)**	**(191)**	**(92)**	**(14)**	**(1,141)**
Depreciation and amortization	**(244)**	**(238)**	**(128)**	**(75)**	**(7)**	**(692)**
	552	**323**	**251**	**97**	**(21)**	**1,202**
Income/(loss) from equity investments	**-**	**-**	**-**	**221**	**(6)**	**215**
Other income/(expense)	**25**	**(9)**	**27**	**47**	**(78)**	**12**
Interest expense	**(192)**	**(125)**	**(75)**	**(49)**	**(91)**	**(532)**
Income taxes recovery/(expense)	**(81)**	**(47)**	**(66)**	**(110)**	**92**	**(212)**
Earnings	**304**	**142**	**137**	**206**	**(104)**	**685**
Earnings attributable to noncontrolling interests	**(2)**	**-**	**(1)**	**(21)**	**-**	**(24)**
Preferred share dividends	**-**	**-**	**-**	**-**	**(5)**	**(5)**
Earnings attributable to Enbridge Inc. common shareholders	**302**	**142**	**136**	**185**	**(109)**	**656**
Additions to property, plant and equipment 1	**734**	**306**	**408**	**56**	**12**	**1,516**
Total assets	**12,135**	**7,393**	**5,784**	**4,053**	**1,965**	**31,330**

Nine months ended September 30, 2010 *(unaudited; millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	1,194	1,822	7,729	239	-	10,984
Commodity costs	-	(932)	(7,289)	-	-	(8,221)
Operating and administrative	(431)	(366)	(157)	(86)	(9)	(1,049)
Depreciation and amortization	(207)	(231)	(102)	(64)	(8)	(612)
	556	293	181	89	(17)	1,102
Income from equity investments	-	-	-	20	2	22
Other income/(expense)	108	(13)	24	35	23	177
Interest expense	(163)	(137)	(67)	(41)	(100)	(508)
Income taxes recovery/(expense)	(104)	(43)	(49)	(31)	74	(153)
Earnings	397	100	89	72	(18)	640
(Earnings)/loss attributable to noncontrolling interests	(2)	(5)	-	9	-	2
Preferred share dividends	-	-	-	-	(5)	(5)
Earnings attributable to Enbridge Inc. common shareholders	395	95	89	81	(23)	637
Additions to property, plant and equipment 1	573	232	755	81	1	1,642
Total assets	11,420	3,848	6,007	7,231	588	29,094

1 Includes AEDC

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

On June 24, 2011, the National Energy Board (NEB) approved the 10-year Competitive Toll Settlement (CTS) agreement reached between Enbridge and shippers on its crude oil mainline system (Canadian Mainline). Prior to the implementation of the CTS on July 1, 2011, 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 for its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost-of-service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset related to future income taxes recorded at the date of discontinuance of approximately $470 million will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the date of discontinuance, and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. Canadian Mainline property, plant and equipment balances will continue to be recognized at historic cost subject to normal course impairment assessment.

4. ACQUISITIONS

On June 30, 2011, the Company invested $144 million to acquire an additional interest in Noverco Inc. (Noverco), which resulted in an increase in Reciprocal shareholding of $33 million. Noverco owns approximately 71.0% of Gaz Metro Limited Partnership, a natural gas distribution company. There has been no change in the accounting for the Company s common or preferred share investments in Noverco as a result of the restructuring. The Company s interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

On June 14**,** 2011, the Company acquired an additional 10% interest in Talbot Windfarm, LP (Talbot), a wind energy project, for $28 million, increasing its ownership interest to 100%. The Company s interest in Talbot continues to be held within the Gas Pipelines, Processing and Energy Services segment and is consolidated with the Company s results both before and after the acquisition.

On August 9, 2010, the Company acquired an additional 20% interest in Olympic Pipeline Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture. The Company s interest in Olympic continues to be held within the Liquids Pipeline segment.

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty. Prior to June 16, 2010, the entity was accounted for as a joint venture. The Company s interest in Hardisty continues to be held within the Liquids Pipelines segment.

5. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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 movements. In June 2011, the Company entered into additional derivative instruments to mitigate the volatility of short-term interest rates on interest expense through 2015 at an average rate of 2.42%.

At September 30, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in a $18 million increase (2010 - nil) in earnings and would have caused a $333 million increase (2010 - $310 million) in Other Comprehensive Income (OCI) due to the revaluation of interest rate derivatives outstanding at September 30, 2011, and a $20 million decrease (2010 - $23 million) in earnings due to increased interest expense related to the Company s variable rate debt outstanding at September 30, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Earnings for the nine months ended September 30, 2011 included a loss of $4 million (2010 - nil) as a result of ineffectiveness on interest rate derivatives used as cash flow hedges.

Foreign Exchange and Commodity Price Risk

As a result of renegotiations with shippers on certain pipelines, the Company is now exposed to additional foreign exchange rate risk on United States dollar denominated revenues and additional commodity price risk resulting from increased exposure to variable crude oil and power prices.

The Company s earnings, cash flows and OCI are subject to foreign exchange variability, primarily arising from its United States dollar denominated investments, subsidiaries and certain revenues denominated in United States dollars. In June 2011, the Company entered into additional derivative instruments to mitigate cash flow volatility due to the effect of future foreign exchange rate fluctuations. These derivative instruments are classified as non-qualifying with changes in fair value recognized in Transportation and other services revenues.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at September 30, 2011 would have resulted in a $248 million increase to earnings (2010 - $72 million) due to the revaluation of foreign exchange derivative instruments. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company s United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

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. During the nine months ended September 30, 2011, the Company entered into additional power swap and crude oil derivative instruments to fix a portion of the variable price exposures arising from operating costs associated with certain transportation agreements. These derivative instruments are classified as non-qualifying with changes in fair value recognized in Transportation and other services revenues, as well as in Operating and administrative expenses.

The Company has defined Earnings at Risk (EaR) limits for different components of businesses exposed to commodity price risk. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. For the nine months ended September 30, 2011 and 2010, the Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from total commodity price risk over a one month period.

	2011	2010
(millions of Canadian dollars)		

Average EaR during the year	**23**	21
High EaR during the year	**27**	25
Low EaR during the year	**18**	16
Closing EaR at quarter end	**21**	25

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

11

	September 30, 2011		December 31, 2010	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards - purchase *(millions of United States dollars)*	**2011-2020**	**1,211**	2011-2020	1,185
U.S. dollar forwards - sell *(millions of United States dollars)*	**2011-2020**	**8,870**	2011-2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	**2011-2029**	**14,199**	2011-2029	10,772
Commodity contracts - energy *(billions of cubic feet equivalent)*	**2011-2013**	**38**	2011-2013	41
Commodity contracts - power *(megawatts per hour)*	**2011-2024**	**54**	2011-2024	2

6. SHARE CAPITAL

Preferred Share Issuance

On September 30, 2011, the Company issued Series B Preferred Shares for gross proceeds of $500 million. The twenty million 4.0% Cumulative Redeemable Preferred Shares, Series B are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company, may at its option, redeem all or a portion of the outstanding preferred shares for $25 per share plus all accrued and unpaid dividends, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series B Preferred Shares will have the right to convert their shares into Cumulative Redeemable Preferred Shares, Series C, subject to certain conditions, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series C Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.40%.

Stock Split

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

7. POST-EMPLOYMENT 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 post-employment benefits (OPEB) for qualifying retired employees. Costs related to the period are presented below.

NET PENSION PLAN AND OPEB COSTS

	Three months ended	Nine months ended

	September 30,		September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars)				
Benefits earned during the period	**17**	14	**50**	42
Interest cost on projected benefit obligations	**22**	20	**64**	61
Expected return on plan assets	**(23)**	(20)	**(70)**	(61)
Amortization of unrecognized amounts	**6**	5	**19**	15
Amount charged to Enbridge Energy Partners, L.P. (EEP)	**(5)**	(4)	**(15)**	(14)
Pension and OPEB costs	**17**	15	**48**	43

The table reflects the pension and OPEB cost for all the Company s benefit plans on an accrual basis. However, for the Gas Distribution pension and OPEB plans, partially offsetting long-term regulatory assets and liabilities have been recorded as plan contributions and actual OPEB benefit costs are recovered through rates.

8. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $2,086 million which are expected to be paid within the next five years and thereafter.

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

Enbridge Gas Distribution Inc. (EGD) was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and in April 2010 the Superior Court overturned the trial judge s decision and ordered a new trial to be conducted before a different judge. EGD commenced a motion for leave to appeal to the Ontario Court of Appeal, but the Court of Appeal dismissed EGD s motion in January 2011. As a result, the Superior Court s decision ordering a new trial will stand. The new trial is scheduled to commence in November 2011. Management does not believe any fines that may be levied will have a material financial impact on the Company.

ENBRIDGE ENERGY PARTNERS, L.P.

EEP Lakehead System Line 6B and 6A Crude Oil Releases

Enbridge holds an approximate 23.8% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Crude Oil Release

As a result of EEP s response to recent additional work direction from the Environmental Protection Agency (EPA), additional information concerning the reassessment of the overall monitoring area, related clean up, including submerged oil recovery operations, and remediation activities, EEP has revised its total estimate for costs related to the crude oil release on Line 6B of its Lakehead System to US$725 million ($123 million after-tax net to Enbridge), before insurance recoveries, as of September 30, 2011, an increase of US$140 million ($21 million after-tax net to Enbridge) from June 30, 2011. The US$140 million increase includes estimated costs related to the additional scope of work set forth in EEP s response to an EPA directive that was submitted to the EPA on October 20, 2011. EEP continues to make progress on the clean up, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at September 30, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. 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 as well as 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 for any additional requirements. The clean up, remediation and restoration of the areas affected by the release has been substantially completed. EEP s cost estimate in connection with this crude oil release remains at approximately US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential to incur 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

The Company maintains 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 increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates are likely to exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$85 million ($13 million after-tax net to Enbridge) and US$135 million ($21 million after-tax net to Enbridge) of insurance recoveries in the three and nine months ended September 30, 2011, respectively, for claims filed in connection with the Line 6B crude oil release. Of the US$135 million of insurance recoveries recognized in earnings to date, EEP had received insurance payments of US$50 million as at September 30, 2011 while the remaining US$85 million was received in November 2011. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period that it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

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. Currently, 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. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at September 30, 2011. 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 LEGAL AND REGULATORY PROCEEDINGS

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

9. RELATED PARTY TRANSACTIONS

In connection with the Lakehead Line 6B crude oil release, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean up and remediation efforts. These services, which were charged at cost, totaled $1 million (2010 - $7 million) and $5 million (2010 - $7 million) for the three and nine months ended September 30, 2011, respectively.

10. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars, except per share amounts)				
Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP	**4**	157	**656**	637
Earnings attributable to Enbridge Inc. under Canadian GAAP	**5**	158	**661**	642
Dilution gains, net of tax[1]	**-**	(4)	**-**	(5)
Gain on acquisition, net of tax[2]	**-**	-	**-**	20
Inventory valuation adjustment, net of tax[3]	**(6)**	(2)	**14**	21
Amortization of underfunded pension adjustment[4]	**(1)**	(1)	**(3)**	(3)
Other[9,10]	**1**	1	**-**	-
Earnings/(loss) attributable to noncontrolling interests				
EEP	**58**	(272)	**203**	(128)
Other	**5**	(27)	**24**	(1)
Earnings/(loss) under U.S. GAAP	**62**	(147)	**899**	546
(Earnings)/loss attributable to noncontrolling interests	**(63)**	299	**(227)**	129
Earnings/(loss) attributable to Enbridge Inc. under U.S. GAAP	**(1)**	152	**672**	675
Preferred share dividends	**(1)**	(1)	**(5)**	(5)
Earnings/(loss) attributable to Enbridge Inc. common shareholders under U.S. GAAP	**(2)**	151	**667**	670
Earnings per common share attributable to Enbridge Inc. common shareholders under U.S. GAAP	**-**	0.41	**0.89**	1.82
Diluted earnings per common share attributable to Enbridge Inc. common shareholders under U.S. GAAP	**-**	0.40	**0.88**	1.80

COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars)				
Earnings/(loss) under U.S. GAAP	**62**	(147)	**899**	546
Other comprehensive loss including noncontrolling interests under Canadian GAAP	**(57)**	(249)	**(154)**	(297)
Underfunded pension adjustment4	**4**	4	**13**	11
Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP5	**(42)**	(35)	**(80)**	(65)
Other comprehensive loss including noncontrolling interests under U.S. GAAP	**(95)**	(280)	**(221)**	(351)
Comprehensive income/(loss)	**(33)**	(427)	**678**	195
Comprehensive (income)/loss attributable to noncontrolling interests	**(42)**	353	**(150)**	218
Comprehensive income/(loss) attributable to Enbridge Inc. under U.S. GAAP	**(75)**	(74)	**528**	413
Preferred share dividends	**(1)**	(1)	**(5)**	(5)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders under U.S. GAAP	**(76)**	(75)	**523**	408

FINANCIAL POSITION

	September 30, 2011		December 31, 2010	
	Canada	**United States**	Canada	United States
(unaudited; millions of Canadian dollars)				
Assets				
Current assets				
Cash and cash equivalents[5,7]	**584**	**1,007**	242	356
Accounts receivable and other[5,7,10]	**2,435**	**3,335**	2,706	3,582
Inventory[3,5,7]	**762**	**901**	813	913
	3,781	**5,243**	3,761	4,851
Property, plant and equipment, net[5,7,9,10]	**21,218**	**30,359**	20,332	28,562
Long-term investments[5,7]	**2,487**	**502**	2,198	367
Deferred amounts and other assets[4,5,7,8,10]	**2,936**	**2,389**	2,886	2,168
Intangible assets[5,9]	**478**	**683**	478	676
Goodwill[5,9]	**388**	**462**	385	445
Future income taxes[7]	**42**	**41**	80	79
	31,330	**39,679**	30,120	37,148
Liabilities and shareholders equity				
Current liabilities				
Short-term borrowings	**430**	**430**	326	326
Accounts payable and other[5,7,10]	**2,600**	**3,868**	2,688	3,806
Interest payable[5]	**140**	**223**	117	177
Current maturities of long-term debt[5]	**2**	**34**	154	185
Current maturities of non-recourse long-term debt[7]	**94**	**75**	70	68
	3,266	**4,630**	3,355	4,562
Long-term debt[5,8,9]	**13,550**	**18,825**	13,561	18,374
Non-recourse long-term debt[7]	**1,016**	**664**	1,061	701
Other long-term liabilities[4,5,7,10]	**2,034**	**2,431**	1,473	1,611
Future income taxes[3,4,7,9]	**2,553**	**2,470**	2,447	2,352
	22,419	**29,020**	21,897	27,600
Redeemable noncontrolling interests[6]	**-**	**370**	-	364
Shareholders equity				
Share capital				
Preferred shares	**613**	**613**	125	125
Common shares	**3,901**	**3,901**	3,683	3,683
Contributed surplus	**114**	**-**	59	-
Retained earnings[3,4,6,9,10]	**4,840**	**4,064**	4,734	3,980
Additional paid-in capital[9]	**-**	**186**	-	131
Accumulated other comprehensive loss[4]	**(1,039)**	**(1,163)**	(882)	(1,005)
Reciprocal shareholding	**(187)**	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders equity	**8,242**	**7,414**	7,565	6,760
Noncontrolling interests[5,6]	**669**	**2,875**	658	2,424
	8,911	**10,289**	8,223	9,184
	31,330	**39,679**	30,120	37,148

1. Dilution Gains

At September 30, 2010, under Canadian GAAP, dilution gains were recorded as an increase to earnings. Under U.S. GAAP, dilution gains were recorded as equity transactions. At September 30, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists. During the three and nine months ended September 30, 2010, $4 million and $5 million, respectively, net of tax, of dilution gains were reclassified from earnings to equity.

2. Gain on Acquisition

At September 30, 2010, under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control is obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At September 30, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of Hardisty, a $20 million gain, net of tax, was recorded in earnings during the nine months ended September 30, 2010 under U.S GAAP.

3. Commodity Inventories Valuation

Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the nine months ended September 30, 2011, lower of cost or market adjustments resulted in a $9 million (December 31, 2010 - $33 million) decrease to inventory, a $2 million (December 31, 2010 - $12 million) decrease to the future income tax liability and a $14 million (2010 - $21 million) increase to earnings.

4. Pension Accounting

U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $336 million (December 31, 2010 - $335 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $132 million (December 31, 2010 - $132 million), a decrease in future tax liability of $70 million (December 31, 2010 - $70 million) and an increase in accumulated other comprehensive loss of $123 million (December 31, 2010 - $136 million) at September 30, 2011. Approximately $13 million (2010 - $11 million) related to pension and OPEB plans was reclassified into OCI during the nine months ended September 30, 2011.

Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At September 30, 2011, this adjustment resulted in a $3 million (December 31, 2010 - $3 million) increase to the net pension asset with an offset to retained earnings.

Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At September 30, 2011, this adjustment resulted in an $90 million decrease (December 31, 2010 - $85 million) to regulatory assets with a corresponding decrease to retained earnings, and a $3 million decrease to earnings (2010 - $3 million).

5. Consolidation of a Limited Partnership

Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 23.8% interest in the partnership, resulting in an increase to assets of $9,173 million (December 31, 2010 - $7,972 million), an increase in liabilities of $6,886 million (December 31, 2010 - $6,098 million) and an increase in noncontrolling interests of $2,284 million (December 31, 2010 - $1,871 million) at September 30, 2011 and no recognition or measurement changes to equity or earnings attributable to the Company as at and for the nine months ended September 30, 2011 and 2010.

6. Redeemable Noncontrolling Interests

Under Canadian GAAP, a subsidiary s redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the consolidated statement of financial position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At September 30, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $288 million (December 31, 2010 - $255 million).

7. Accounting for Joint Ventures

Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company s investments in joint ventures be accounted for using the equity method. However, under an accommodation of the United States Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders equity.

8. Transaction Costs

Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in long-term debt. For U.S. GAAP, these costs are reclassified to Deferred amounts and other assets. As at September 30, 2011, $90 million (December 31, 2010 - $89 million) of transaction costs were reclassified.

9. Common Control Transactions

U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At September 30, 2011, a decrease in assets of $409 million (December 31, 2010 - $414 million), a decrease in liabilities of $56 million (December 31, 2010 - $61 million), and a decrease in retained earnings of $353 million (December 31, 2010 - $353 million) related to a historic transaction with Enbridge Income Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was a $1 million decrease to earnings (2010 - $1 million).

10. Accounting for Leases

The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company s pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $124 million (December 31, 2010 - $129 million), an increase in liabilities of $116 million (December 31, 2010 - $122 million), an increase in retained earnings of $8 million (December 31, 2010 - $7 million) and an increase in earnings of $1 million (2010 - $1 million).