ENBRIDGE INC
Form 6-K
May 30, 2014

# 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 May 29, 2014

Commission file number 001-15254

**ENBRIDGE INC.**

(Exact name of Registrant as specified in its charter)

| | |
|---|---|
| **Canada** | **None** |
| (State or other jurisdiction<br>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 X

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 X

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 X

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 X

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 STATEMENT ON FORM F-10 (FILE NO. 333-189157) 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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:

1. Underwriting Agreement dated May 28, 2014 between Enbridge Inc. and the underwriters listed therein.

**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: May 29, 2014

By: /s/ Tyler W. Robinson
Tyler W. Robinson
Vice President & Corporate Secretary



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# NEWS RELEASE

## Enbridge reports third quarter results

### HIGHLIGHTS

- Third quarter earnings were $157 million, or $0.42 per common share; nine month earnings were $637 million, or $1.73 per common share
- Third quarter and nine month adjusted earnings were $196 million, or $0.53 per common share, and $746 million, or $2.02 per common share, respectively
- Enbridge expanded Regional Oil Sands System through more than $2.4 billion in secured expansion projects

- Enbridge affiliates expanded their presence in the Bakken play; proposed addition of 145,000 bpd of capacity will connect to the Enbridge Mainline System

- World s largest operating photovoltaic solar facility (80-MW) brought into service ahead of schedule

- Enbridge affiliate acquired US$700 million gas gathering and processing assets

- Management reorganization reinforces commitment to operational reliability

**CALGARY, ALBERTA, November 3, 2010** Enbridge Inc. (TSX:ENB) (NYSE:ENB) Although the crude oil spills on Line 6B in July and Line 6A in September detracted from an otherwise strong quarter for Enbridge and its affiliate Enbridge Energy Partners, both lines were returned to operations in September and clean-up associated with the spills is substantially complete, said Patrick D. Daniel, President and Chief Executive Officer.

Along with ensuring the continued delivery of crude oil and mitigation of disruptions for our shippers, addressing the impacts to the people, the communities and the environment affected by the spills remains our top priority.

Mr. Daniel said, Apart from the spills, Enbridge s core businesses in liquids pipelines, natural gas transportation and green energy continued to deliver solid and reliable operating and financial performance through the third quarter of 2010, keeping us on track to achieve the upper half of our full year guidance of $2.50 to $2.70 per share.

Reported earnings for the Company reflected clean-up cost accruals before insurance recoveries. Adjusted for items including the accrual of costs related to the Line 6B and Line 6A spills, Enbridge delivered year-to-date adjusted earnings of $746 million, or $2.02 per common share, an adjusted earnings increase of approximately 21% compared with the same period of 2009.

A highlight of the third quarter was the achievement of commercial operations at Enbridge s Sarnia Solar Project, three months ahead of schedule, followed by an announcement of an investment in geothermal generation. The Sarnia Solar Project is the largest operating photovoltaic facility in the world, delivering 80 megawatts of emissions-free energy to the Ontario power grid.

Our investments in green energy are an increasingly important part of Enbridge s business. Over the last year, we ve accelerated our growth plans, adding five new projects totaling $1.6 billion and increasing our total green energy investment to more than $2 billion. In doing so, we ve established a solid platform for

***Forward-Looking Information***

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

attractive and sustainable long-term growth with a risk-return profile consistent with our liquids pipelines and natural gas businesses.

Expansion of the Company s liquids pipelines business continues at a steady pace, with the announcement of several expansions to its oil sands regional infrastructure over the third quarter.

In August, the Company entered into an agreement with Suncor Energy to construct the Wood Buffalo crude oil pipeline and in September signed an agreement to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project. Also in September, Enbridge announced the expansion of its Athabasca Pipeline to accommodate shipping commitments by the Christina Lake oil sands project operated by Cenovus, as well as the construction of four new tanks, adding one million barrels of storage capacity, at its mainline terminal at Edmonton, Alberta.

Enbridge has announced approximately $2.4 billion in commercially secured projects to expand and extend its Regional Oil Sands System, said Mr. Daniel. By 2013, eight oil sands projects will be connected to our system. As the largest operator of oil sands regional infrastructure, and with our corresponding ability to provide favourable and competitive transportation solutions to producers, we expect to see continued attractive investment opportunities.

The Bakken Formation is another key region where Enbridge and its affiliates are able to leverage the Company s existing infrastructure to capture new growth opportunities. In the third quarter, Enbridge affiliates announced a suite of projects to further expand transportation options for Bakken producers. The Bakken Expansion Program will provide firm access from North Dakota oilfields to the two million barrel per day (bpd) Enbridge Mainline System, giving them excellent connectivity into North American refinery and marketing hubs.

In gas transportation, Enbridge expanded its interests in U.S.-based natural gas gathering and processing assets through the acquisition by the Partnership, from Atlas Pipeline Partners, of the Elk City Gathering and Processing System for US$686 million.

Natural gas is going to be an increasing and important part of meeting North American energy demand, said Mr. Daniel. Strategically, this acquisition further solidifies Enbridge s ability to capitalize on growth in the Granite Wash.

In October, Mr. Daniel announced a new organizational structure for Enbridge.

Enbridge has a strong leadership team clearly focused on delivering superior value to our shareholders through the reliable operation and profitable growth of our core businesses, said Mr. Daniel. Our new organizational structure reflects the continued growth and evolution of the Company and enhances our emphasis on operational reliability across those businesses.

The causes of the two spills are under investigation. We are committed to taking the learnings from these incidents, applying them to future operations and sharing them with industry to reduce the likelihood of such incidents in the future.

Effective November 2, 2010, the Enbridge Board appointed as a director Maureen Kempston Darkes, O.C., O. Ont. Ms. Kempston Darkes is the retired Group Vice President and President, Latin America, Africa and Middle East, General Motors Corporation, and was the first woman to lead General Motors of Canada. She is currently a director of Canadian National Railway Company, Brookfield Asset Management and Irving Oil.

We are delighted to welcome Ms. Kempston Darkes to Enbridge s Board, said Mr. Daniel. As a successful and accomplished Canadian business woman with experience in the automotive, transportation and energy industries, she will bring a valued perspective to the Board and we look forward to her contribution.

In conclusion, Mr. Daniel commented on Enbridge s future prospects.

Enbridge s strategic position and competitive advantages continue to present us with a significant volume of exceptional investment opportunities. We have the financial capacity to convert attractive investment opportunities into earnings, cash flow and, ultimately, value for investors, concluded Mr. Daniel.

**THIRD QUARTER 2010 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.

- Many of the same factors which contributed to favourable results in the first and second quarters of 2010 continued to impact adjusted earnings in the third quarter. Adjusted results were positively affected by Alberta Clipper and Southern Lights Pipeline being placed into service in April 2010 and July 2010, respectively, as well as strong performance from the Company s existing asset base. Although volumes were off slightly for the quarter due to the loss of capacity associated with the crude oil releases, Enbridge Energy Partners, L.P. (EEP) made a positive contribution to adjusted earnings due to higher average volumes and tolls on the Lakehead System due to recent expansions. Enbridge Gas Distribution (EGD) also had improved performance, including the impact of customer growth.

- Lines 6B and 6A were returned to service in September 2010 following crude oil releases in July and September, respectively; with clean up efforts nearing completion. Equity earnings from the Company s investment in EEP reflect impacts of $85 million related to these incidents. Addressing the impacts to people, communities and environment affected by the spills remains the Company s top priority.

- On October 4, 2010, the Company announced the completion of the 80-megawatt (MW) Sarnia Solar Project. The initial 20-MW facility attained commercial operation in December 2009 and the 60-MW expansion was completed three months ahead of schedule in early September 2010. Power output of the facility is sold to the Ontario Power Authority (OPA) under a 20-year power purchase agreement. The final capital cost of both facilities was approximately $0.4 billion.

- On September 29, 2010, Enbridge announced the Edmonton Terminal Expansion Project, which 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, which is expected to be completed by late 2012, is required to accommodate growing oil sands production receipts both from Enbridge s Waupisoo Pipeline and other non-Enbridge pipelines. Subject to regulatory approval, construction will commence in early 2011. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of a short segment of pipeline and related infrastructure.

- On September 8, 2010, the Company announced that it will partner 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. Once completed, which is expected to be in the second quarter of 2012, the project will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Enbridge will invest up to $24 million for a 20% interest in the plant.

- On September 7, 2010, Enbridge announced that it had entered into an agreement to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project. The Company will construct a new originating terminal (Hartley Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Hartley Terminal to the Cheecham Terminal and additional tankage at Cheecham. The estimated cost of the project, with an initial capacity of 90,000 barrels per day (bpd), expandable to 270,000 bpd, is approximately $0.5 billion. Subject to regulatory approval, the facilities are expected to be in service in late 2013.

- On September 2, 2010, the Company announced it will undertake an expansion of its Athabasca Pipeline to accommodate recent shipping commitments by the Christina Lake Oil Sands Project operated by Cenovus, at an estimated cost of $0.2 billion. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta. Following this expansion, which is expected to be in service in the third quarter of 2013, the capacity of the Athabasca Pipeline will be up to 430,000 bpd depending on crude slate. The Athabasca Pipeline can be expanded to as much as 600,000 bpd and, depending on the needs of other shippers, the scope of this expansion may be revised upward prior to regulatory filing.

- In September 2010, EEP, an affiliate of the Company, acquired the Elk City Gathering and Processing (ECOP) System from Atlas Pipeline Partners for US$0.7 billion. The ECOP assets extend from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The ECOP System consists of approximately 2,880 kilometers (1,800 miles) of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day (mmcf/d), and a combined natural gas liquids production capability of 20,000 bpd.

- On August 26, 2010, Enbridge entered into an agreement with Suncor Energy Inc. to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal, which is adjacent to Suncor s oil sands plant, to the Cheecham Terminal, which is the origin point of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline 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 and, pending regulatory approval, the new pipeline is expected to be in service by mid-2013.

- On August 24, 2010, Enbridge, EEP and Enbridge Income Fund (EIF) announced they will proceed, subject to customary regulatory approvals, with a joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana and North Dakota. The Bakken Expansion Program will increase takeaway capacity from the Bakken area by an initial 145,000 bpd, which can be readily expanded 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 EIF at a cost of approximately $0.2 billion, excluding expansion costs to be incurred by Enbridge at the Cromer Terminal. EEP and EIF have received sufficient long-term shipping commitments from anchor shippers to enable the Bakken Expansion Program to proceed. A binding Open Season is underway to provide other shippers with the opportunity to make commitments on the same terms as provided to anchor shippers. The Bakken Expansion Program is expected to be completed by the first quarter of 2013.

**DIVIDEND DECLARATION**

On November 2, 2010, the Enbridge Board of Directors declared quarterly dividends of $0.425 per common share and $0.34375 per Series A Preferred Share. Both dividends are payable on December 1, 2010 to shareholders of record on November 15, 2010.

## CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, November 3, 2010 at 9:00 a.m. Eastern time (7:00 a.m. Mountain time) to discuss the third quarter 2010 results. Analysts, members of the media and other interested parties can access the call at +617-213-8068 or toll-free at 1-866-770-7146 using the access code of 75461254. The call will be audio webcast live at www.enbridge.com/InvestorRelations.aspx. A webcast replay will be available approximately two hours after the conclusion of the event and a transcript and MP3 replay will be posted to the website within 24 hours. The replay at toll-free 1-888-286-8010 or +617-801-6888 (access code 46753866) will be available until November 10, 2010.

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 follow the analysts session.

**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.**

### About Enbridge Inc.

Enbridge Inc. (Enbridge or the Company), a Canadian company, is a North American leader in energy delivery 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 green energy technologies, including wind and solar energy projects, 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 6,000 people, primarily in Canada and the U.S. 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, 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 suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected tariffs for pipelines; expected capital expenditures; and estimated future dividends.*

*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 ongoing 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, which represent earnings or loss applicable 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 within the Company s MD&A. Management believes that the presentation of adjusted earnings provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings to set targets, assess performance of the Company and set the Company s dividend payout target. Adjusted earnings and adjusted earnings 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. See Non-GAAP Reconciliations section of the Company s MD&A for a reconciliation of the GAAP and non-GAAP measures.

**ENBRIDGE CONTACTS**

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Email: guy.jarvis@enbridge.com

## HIGHLIGHTS

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| **Earnings Applicable to Common Shareholders** | | | | |
| Liquids Pipelines | **128** | 116 | **395** | 304 |
| Natural Gas Delivery and Services | **10** | 15 | **192** | 539 |
| Sponsored Investments | **(28)** | 31 | **81** | 103 |
| Corporate | **47** | 142 | **(31)** | 309 |
| | **157** | 304 | **637** | 1,255 |
| Earnings per Common Share | **0.42** | 0.83 | **1.73** | 3.45 |
| Diluted Earnings per Common Share | **0.42** | 0.83 | **1.71** | 3.43 |
| **Adjusted Earnings**[1] | | | | |
| Liquids Pipelines | **128** | 119 | **395** | 313 |
| Natural Gas Delivery and Services | **22** | 2 | **213** | 205 |
| Sponsored Investments | **59** | 42 | **161** | 112 |
| Corporate | **(13)** | (10) | **(23)** | (14) |
| | **196** | 153 | **746** | 616 |
| Adjusted Earnings per Common Share[1] | **0.53** | 0.42 | **2.02** | 1.70 |
| **Cash Flow Data** | | | | |
| Cash provided by operating activities | **319** | 244 | **1,476** | 1,835 |
| Cash used in investing activities | **(741)** | (1,293) | **(1,928)** | (2,144) |
| Cash provided by financing activities | **490** | 1,113 | **597** | 197 |
| **Dividends** | | | | |
| Common Share Dividends Declared | **163** | 139 | **485** | 416 |
| Dividends per Common Share | **0.425** | 0.370 | **1.275** | 1.110 |
| **Shares Outstanding** *(millions)* | | | | |
| Weighted average common shares outstanding | **371** | 365 | **369** | 364 |
| Diluted weighted average common shares outstanding | **375** | 367 | **373** | 366 |
| **Operating Data** | | | | |
| Liquids Pipelines - Average Deliveries *(thousands of barrels per day)* | | | | |
| Enbridge System[2] | **2,158** | 2,094 | **2,141** | 2,038 |
| Enbridge Regional Oil Sands System[3] | **307** | 268 | **279** | 265 |
| Spearhead Pipeline | **142** | 141 | **139** | 119 |
| Olympic Pipeline | **289** | 294 | **276** | 280 |
| Natural Gas Delivery and Services | | | | |
| Gas Pipelines - Average Throughput Volumes *(millions of cubic feet per day)* | | | | |
| Alliance Pipeline US | **1,551** | 1,559 | **1,604** | 1,612 |
| Vector Pipeline | **1,329** | 1,098 | **1,399** | 1,324 |
| Enbridge Offshore Pipelines | **1,998** | 2,191 | **1,983** | 2,051 |
| Enbridge Gas Distribution | | | | |
| Volumes *(billions of cubic feet)* | **40** | 41 | **265** | 294 |
| Number of active customers[4] *(thousands)* | **1,957** | 1,966 | **1,957** | 1,966 |
| Degree day deficiency[5] | | | | |
| Actual | **79** | 70 | **2,151** | 2,500 |
| Forecast based on normal weather | **83** | 83 | **2,336** | 2,316 |

1. Adjusted earnings represent earnings applicable 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.

2. Enbridge System includes Canadian mainline 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.

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

4. Number of active customers is the number of natural gas consuming Enbridge Gas Distribution customers at the end of the period.

5. Degree day deficiency 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, 2010

# MANAGEMENT S DISCUSSION AND ANALYSIS

## FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2010

This Management s Discussion and Analysis (MD&A) dated November 2, 2010 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, 2010, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company s Annual Report for the year ended December 31, 2009. 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 and on the Company s website at www.enbridge.com.

## CONSOLIDATED EARNINGS

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| Liquids Pipelines | **128** | 116 | **395** | 304 |
| Natural Gas Delivery and Services | **10** | 15 | **192** | 539 |
| Sponsored Investments | **(28)** | 31 | **81** | 103 |
| Corporate | **47** | 142 | **(31)** | 309 |
| Earnings Applicable to Common Shareholders | **157** | 304 | **637** | 1,255 |
| Earnings per Common Share | **0.42** | 0.83 | **1.73** | 3.45 |
| Diluted Earnings per Common Share | **0.42** | 0.83 | **1.71** | 3.43 |

Earnings applicable to common shareholders were $157 million for the three months ended September 30, 2010, or $0.42 per common share, compared with $304 million, or $0.83 per common share, for the three months ended September 30, 2009. This decrease primarily reflected an $85 million charge to earnings from Enbridge Energy Partners, L.P. (EEP) as a result of the Lakehead System Line 6B and 6A crude oil releases and associated remediation as well as a $63 million decrease in unrealized fair value gains on derivative financial instruments used to manage foreign exchange risk. These decreases were partially offset by increased earnings in Liquids Pipelines due to Alberta Clipper being placed in service in the second quarter of 2010 and Southern Lights Pipeline entering service in the third quarter of 2010.

Earnings applicable to common shareholders were $637 million for the nine months ended September 30, 2010, or $1.73 per common share, compared with $1,255 million, or $3.45 per common share, for the same period of 2009. This decrease primarily reflected a $329 million after-tax gain recognized on the sale of the Company s investment in Oleoducto Central S.A. (OCENSA) in March 2009, an after-tax gain of $25 million related to the sale of NetThruPut (NTP) in May 2009 and an $85 million charge to earnings as a result of the crude oil releases. As well, unrealized fair value losses on derivative financial instruments used to manage foreign exchange risk were recognized in 2010 compared with unrealized gains in the first nine months of 2009, a resultant variance of $197 million. Similarly, movements in unrealized foreign exchange gains on intercompany balances accounted for $103 million of the reduction in earnings period over period. The decreases were partially offset by increased earnings in Liquids Pipelines due to Alberta Clipper being placed in service in the second quarter of 2010 and Southern Lights Pipeline entering service in the third quarter of 2010.

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**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, 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 suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected tariffs for pipelines; expected capital expenditures; and estimated future dividends.*

*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 ongoing 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 applicable 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 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 section for a reconciliation of the GAAP and non-GAAP measures.

## ADJUSTED EARNINGS

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| Liquids Pipelines | **128** | 119 | **395** | 313 |
| Natural Gas Delivery and Services | **22** | 2 | **213** | 205 |
| Sponsored Investments | **59** | 42 | **161** | 112 |
| Corporate | **(13)** | (10) | **(23)** | (14) |
| Adjusted Earnings | **196** | 153 | **746** | 616 |
| Adjusted Earnings per Common Share | **0.53** | 0.42 | **2.02** | 1.70 |

Adjusted earnings were $196 million, or $0.53 per common share, for the three months ended September 30, 2010, compared with $153 million, or $0.42 per common share, for the three months ended September 30, 2009. Adjusted earnings were $746 million, or $2.02 per common share, for the nine months ended September 30, 2010, compared with $616 million, or $1.70 per common share, for the nine months ended September 30, 2009.

The adjusted earnings growth achieved in both the third quarter of 2010 and the nine-month period ended September 30, 2010 reflects the successful execution of several growth projects, including Alberta Clipper, the largest liquids pipelines project in the Company s history, and Southern Lights Pipeline, as well as strong performance from the Company s existing asset base.

Specifically, the following factors impacted adjusted earnings for both the three and nine months ended September 30, 2010:

- Within Liquids Pipelines, contributions from Alberta Clipper and Southern Lights Pipelines which were placed into service on April 1, 2010 and July 1, 2010, respectively, as well as improved operating results on the Enbridge System and Spearhead Pipeline.

- Continued favourable performance at Enbridge Gas Distribution (EGD) under Incentive Regulation (IR), reflecting customer growth and lower taxes, partially offset by higher accrued estimated customer earnings sharing and depreciation expense on a higher rate base.

- Although volumes were off slightly for the quarter due to the loss of capacity associated with the crude oil releases, EEP s year-to-date adjusted contribution increased resulting from higher average volumes and tolls on the Lakehead System due to recent expansions, including the completion of Southern Access Expansion Phase II in April 2009 and the North Dakota System Expansion that entered service on January 1, 2010.

- Adjusted earnings for the nine months ended September 30, 2010 and 2009 also include allowance for equity funds used during construction (AEDC) on the Alberta Clipper Project and Southern Lights Pipeline while these projects were under construction.

## RECENT DEVELOPMENTS

**Management Organizational Structure**

On October 4, 2010, the Company announced a new organizational structure that capitalizes on the strengths of the team and reflects the continued growth and evolution of the Company. The changes in its senior management team are as follows.

- Janet A. Holder, President, Gas Distribution will be responsible for the overall leadership and operations of EGD as well as Enbridge Gas New Brunswick, Gazifere and St. Lawrence Gas.

- Al Monaco, President, Gas Pipelines, Green Energy & International, will be responsible for the gas pipelines and gas gathering and processing businesses of the Company and its affiliates, as well as Enbridge Offshore Pipelines (Offshore) and the Company s investments in Alliance Pipeline, Vector Pipeline and Aux Sable. Mr. Monaco will also have responsibility for Enbridge s International and Green Energy business development and investment activities.

• Stephen J. Wuori, President, Liquids Pipelines, will continue to be responsible for the Liquids Pipelines businesses of the Company and its affiliates.

• David T. Robottom, Executive Vice President & Chief Legal Officer, will be responsible for Law, Information Technology and Public Affairs.

• J. Richard Bird remains Executive Vice President, Chief Financial Officer & Corporate Development.

**LIQUIDS PIPELINES**

**Alberta Clipper Project**

The Alberta Clipper Project, which was placed in service April 1, 2010 on schedule and on budget, involved the construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior, Wisconsin generally within or alongside Enbridge s existing rights-of-way in Canada and EEP s existing rights-of-way in the United States. The new pipeline interconnects with the existing mainline system in Superior where it provides access to Enbridge s full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka and Cushing. Alberta Clipper has an initial capacity of 450,000 barrels per day (bpd), is expandable to 800,000 bpd and now forms part of the existing Enbridge System in Canada and the EEP Lakehead System in the United States.

The cost of the project was $2.2 billion and US$1.2 billion, including allowance for funds used during construction (AFUDC), for the Canadian and United States segments, respectively. Enbridge funded 66.7% of the United States segment of the Alberta Clipper project through Enbridge Energy, L.P. (EELP).

For the United States segment of Alberta Clipper, tariffs filed with the Federal Energy Regulatory Commission (FERC) were approved and became effective April 1, 2010. Filings in early 2010 by shippers requesting the FERC to delay the tariff were dismissed by the FERC in March 2010.

Interim tolls for the Enbridge mainline, including recovery of costs related to the Canadian segment of Alberta Clipper, went into effect April 1, 2010 and, as directed by the National Energy Board (NEB), reflected the forecasted Alberta Clipper toll presented in 2007. A NEB hearing was originally scheduled for November 2010 which would have considered Enbridge s final toll application, including Alberta Clipper at the full revenue requirement based on it being used and useful, as well as remaining aspects of the February 2010 filing made by certain shippers. However, at the joint request of the primary intervenors and the Company, the NEB hearing has been suspended. The Company and the intervenors are currently in discussions that could, if successful, reduce the existing issues, minimize the scope of or eliminate the need for the hearing. The Company continues to believe the shippers Alberta Clipper filings to be without merit.

**Southern Lights Pipeline**

The Southern Lights Pipeline was completed ahead of schedule and was placed in service on July 1, 2010. The 180,000 bpd Southern Lights Pipeline transports diluent from Chicago, Illinois to Edmonton, Alberta. The project included reversing the flow of a portion of Enbridge s Line 13, a crude oil pipeline which ran from Edmonton to Clearbrook, Minnesota. In order to replace the light crude capacity that would be lost through the reversal of Line 13, the Southern Lights Project also included the construction of a new 20-inch diameter light sour crude oil pipeline (LSr Pipeline) from Cromer, Manitoba to Clearbrook, and modifications to existing Line 2. These changes to the existing crude oil system increased southbound light crude system capacity by approximately 45,000 bpd, net of the Line 13 lost capacity.

The total expected project cost is US$1.6 billion for the United States segment and $0.5 billion for the Canadian segment. Expenditures to date are US$1.5 billion and $0.5 billion for the United States and Canadian segments, respectively. Remaining costs primarily relate to right-of-way restoration and final work on the Line 13 facilities.

Both the Canadian and United States portion of the tariff for uncommitted shippers on the Southern Lights Pipeline has been challenged. Accordingly, a FERC settlement and hearing process has been initiated. No material financial impacts to the Company are anticipated.

**Hardisty Terminal**

In June 2010, the Company acquired the remaining 50% of the Hardisty Caverns Limited Partnership previously owned by CCS Corporation for approximately $52 million. The Hardisty Caverns facility, now wholly owned by Enbridge, includes four salt caverns totaling 3.1 million barrels of capacity, and provides term storage services under long-term contracts.

**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. The expansion project will add 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 plus 240,000 barrels of tankage, that connect to the Athabasca Pipeline. The estimated cost of the additional facilities is approximately $0.3 billion, with expenditures to date of $0.1 billion. The planned in-service date is late 2011.

**Woodland Pipeline**

Enbridge entered into an 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 will be extended from Cheecham to Edmonton in conjunction with the second phase of the Kearl project. 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 from the Energy Resources Conservation Board in June 2010 and the project is now entering construction. The total estimated cost of the pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 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, which is expected to be completed by late 2012, is required to accommodate growing oil sands production receipts both from Enbridge s Waupisoo Pipeline and other non-Enbridge pipelines. Subject to regulatory approval, construction will commence in early 2011. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of a short segment of pipeline and related infrastructure.

**Wood Buffalo Pipeline**

Enbridge entered into agreement with Suncor Energy Inc. to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal, which is adjacent to Suncor s oil sands plant, to the Cheecham Terminal, which is the origin point of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline 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 and, subject to regulatory approval, the new pipeline is expected to be in service by mid-2013.

**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 (Hartley Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Hartley Terminal to the Cheecham Terminal and additional tankage at Cheecham. The estimated cost of the project, with an initial capacity of 90,000 bpd, expandable to 270,000 bpd, is approximately $0.5 billion. Subject to regulatory approval, the facilities are expected to be in service in late 2013.

**Waupisoo Pipeline Expansion**

Subject to regulatory approval, the Waupisoo Pipeline Expansion will provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The project will accommodate shipper commitments of 229,000 bpd, including the additional Leismer oil sands volumes announced in February 2010. The estimated cost of the project is approximately $0.4 billion.

**Athabasca Pipeline Capacity Expansion**

The Company will undertake an expansion of its Athabasca Pipeline to accommodate recent shipping commitments by the Christina Lake Oil Sands Project operated by Cenovus, at an estimated cost of $0.2 billion. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta. Following this expansion, which, subject to regulatory approval, is expected to be in service in the third quarter of 2013, the capacity of the Athabasca Pipeline will be up to 430,000 bpd depending on crude slate. The Athabasca Pipeline can be expanded to as much as 600,000 bpd and, depending on the needs of other shippers; the scope of this expansion may be revised upward prior to regulatory filing.

**Northern Gateway Project**

The Northern Gateway Project involves constructing a twin 1,172-kilometre (728-mile) pipeline system from near Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is expected 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 expected 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 and 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 is of the view that it would be appropriate to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. The Company has secured over $0.1 billion of funding from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project.

Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner, Aboriginal and local community concerns, the Company estimates that Northern Gateway could be in-service in approximately 2016 at an estimated cost of $5.5 billion. The NEB posts public filings related to Northern Gateway on its website and Enbridge also maintains a Northern Gateway Project site 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.notherngateway.ca. None of the information contained on, or connected to, the NEB website, the Northern Gateway Project website or Enbridge s website is incorporated in or otherwise part of this MD&A.

**NATURAL GAS DELIVERY AND SERVICES**

**Walker Ridge Gas Gathering System**

The Company entered into Letters of Intent (LOI) with Chevron Corp. to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the LOI, 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, based on updated estimates, is expected to cost approximately US$0.4 billion.

**Big Foot Oil Pipeline**

The Company entered into a LOI with Chevron USA, Inc., 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 previously announced plans to construct the WRGGS. The updated 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 is expected to be in service in 2014.

**SPONSORED INVESTMENTS**

*Bakken Expansion Program*

Enbridge, EEP and Enbridge Income Fund (EIF) will proceed, subject to customary regulatory approvals, with 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. The Bakken Expansion Program will increase takeaway capacity from the Bakken area by an initial 145,000 bpd, which can be readily expanded 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 EIF at a cost of approximately $0.2 billion, excluding expansion costs to be incurred by Enbridge at the Cromer Terminal. EEP and EIF have received sufficient long-term shipping commitments from anchor shippers to enable the Bakken Expansion Program to proceed. A binding Open Season is underway to provide other shippers with the opportunity to make commitments on the same terms as provided to anchor shippers. The Bakken Expansion Program is expected to be completed by the first quarter of 2013.

**Enbridge Energy Partners, L.P.**

*Elk City Gathering and Processing System*

In September 2010, EEP acquired the entities that comprise the Elk City Gathering and Processing (ECOP) System from Atlas Pipeline Partners for US$0.7 billion. The ECOP assets extend from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The ECOP System consists of approximately 2,880 kilometers (1,800 miles) of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day (mmcf/d) and a combined natural gas liquids production capability of 20,000 bpd.

**Enbridge Income Fund**

*Corporate Restructuring*

In May 2010, EIF unitholders approved a plan of arrangement (the Plan) for restructuring EIF. The restructuring will involve an exchange by Enbridge of a portion of its interest in EIF for shares of a taxable Canadian corporation to be called Enbridge Income Fund Holdings Inc. (EIFH), whose activities will be limited to investment in EIF. Public unitholders will also exchange their trust units for shares of EIFH. Enbridge will retain its 72% economic interest in EIF following completion of the Plan. Subject to final Toronto Stock Exchange approvals, the Plan will take effect prior to the end of 2010.

*Saskatchewan System Capacity Expansion*

Phase II of the Saskatchewan System Capacity Expansion includes three separate projects that will reduce capacity constraints at a variety of locations. Collectively, the projects will increase capacity across the system by approximately 125,000 bpd at an estimated cost of $0.1 billion. Construction continues on all three projects comprising the Phase II Expansion, currently expected to be in service by December 2010.

**CORPORATE**

**Sarnia Solar Project**

The Company developed the 80-megawatt (MW) Sarnia Solar Project with First Solar, Inc. The initial 20-MW facility attained commercial operation in December 2009 and the 60-MW expansion was completed three months ahead of schedule in early September 2010. Power output of the facility is sold to the Ontario Power Authority (OPA) under a 20-year power purchase agreement. The final capital cost of both facilities was approximately $0.4 billion.

**Talbot Wind Energy Project**

Enbridge is developing the 99-MW Talbot Wind Energy Project near Chatham, Ontario with Renewable Energy Systems Canada Inc. (RES Canada). Enbridge will have a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada will construct the wind 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 operations and maintenance services for the wind turbines. The Talbot Wind Energy Project will deliver energy to the OPA under a 20-year power purchase agreement. The project is in the final stage of construction and is expected to be ready for service by December 2010 at an estimated capital cost of $0.3 billion. Expenditures to date are $0.2 billion.

**Greenwich Wind Energy Project**

The Company is developing the 99-MW Greenwich Wind Energy Project on the northern shore of Lake Superior in Ontario will be developed with RES Canada. Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada will construct the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a five-year fixed price agreement, Siemens will provide operations and maintenance services for the wind turbines. The Greenwich Wind Energy Project will deliver energy to the OPA under a 20-year power purchase agreement. Construction of the project has commenced and is expected to be completed in the third quarter of 2011. The total estimated capital cost is $0.3 billion, with expenditures to date of $0.1 billion.

**Cedar Point Wind Energy Project**

Enbridge entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) under which a United States affiliate of Enbridge will own and operate the 250-MW Cedar Point Wind Energy Project, near Denver, Colorado, at an investment of approximately US$0.5 billion. RES Americas is constructing 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. The Cedar Point Wind Energy Project will deliver electricity into the Public Service Company of Colorado grid under a 20-year, fixed price power purchase agreement. Construction on the project has commenced and is expected to be completed in the fourth quarter of 2011, with expenditures to date of US$0.2 billion.

**Neal Hot Springs Geothermal Project**

The Company will partner 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. Once completed, anticipated to be in the second quarter of 2012, the project will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Enbridge will invest up to approximately $24 million for a 20% interest in the plant.

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

Enbridge s exposure to the Line 6B and 6A leaks results from its approximate 27% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment, and EEP s leak remediation costs and lost revenues.

**Line 6B Leak**

On July 26, 2010, EEP confirmed a crude oil release on Line 6B of its Lakehead System near Marshall, Michigan. EEP estimated 19,500 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. Regulatory approval of the pipeline restart plan was obtained from the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA) and, on September 27, 2010, the pipeline was safely brought back into service. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

EEP currently estimates that before insurance recoveries, and not including fines and penalties, costs of approximately US$430 million ($75 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), will be incurred in connection with this incident. These costs include emergency response, environmental remediation and cleanup activities associated with the crude oil release and related pipeline inspection costs. Actual costs incurred may differ from the estimate due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

**Line 6A Leak**

A crude oil release from Line 6A of EEP s Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP currently estimates that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release and related pipeline inspection will be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge). Actual costs incurred may differ from the estimate due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

**Insurance Recoveries**

EEP maintains commercial liability insurance coverage that includes a per incident deductible of approximately US$5 million, excluding fines and penalties, and limits of coverage that are expected to be sufficient to fund the costs and liabilities resulting from the leaks from Lines 6A and 6B. Apart from approximately US$16 million in lost revenues, which is non recoverable as EEP does not maintain insurance coverage for interruption of operations except for water crossings, it is anticipated that substantially all of the costs incurred from the leaks will ultimately be recoverable under EEP s existing insurance policies. EEP expects to record a receivable for any amounts claimed for recovery pursuant to its insurance policies during the period realization of the claim for recovery is deemed probable.

**Pipeline Integrity Commitment**

In connection with the restart of Line 6B, EEP committed to accelerate a process, initiated prior to the leak, to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, EEP will remediate ahead of its original schedule those pipeline anomalies it previously identified between 2007 and 2009 that were scheduled for refurbishment, including anomalies identified for action in a July 2010 PHMSA notification. EEP has agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. 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. The total cost to EEP for these integrity measures and pipeline replacement are estimated to approximate US$110 million, the majority of which is expected to be capital in nature. Additional significant integrity expenditures may be required after this initial remediation program. EEP is currently discussing with its customers recovery of these costs through the tolls on its Lakehead System.

**Legal and Regulatory Proceedings**

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B incidents. Currently, eight actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6 B incident; however, currently no penalties or fines have been assessed against EEP in connection with this incident. Currently, one action or claim related to the Line 6A incident has been filed against Enbridge, EEP or their affiliates in United States federal and state courts. The Company believes this action or claim has been resolved pursuant to an agreed interim order.

## FINANCIAL RESULTS

### LIQUIDS PIPELINES

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Enbridge System | **81** | 79 | **243** | 203 |
| Enbridge Regional Oil Sands System | **20** | 19 | **58** | 52 |
| Southern Lights Pipeline | **17** | 17 | **62** | 44 |
| Spearhead Pipeline | **8** | 5 | **23** | 11 |
| Feeder Pipelines and Other | **2** | (1) | **9** | 3 |
| Adjusted Earnings | **128** | 119 | **395** | 313 |
| Enbridge Regional Oil Sands System - leak remediation costs | **-** | (3) | **-** | (9) |
| Earnings | **128** | 116 | **395** | 304 |

Adjusted earnings for the three months ended September 30, 2010 were $128 million, an increase of $9 million compared with the three months ended September 30, 2009. Adjusted earnings for the nine months ended September 30, 2010 were $395 million, an increase of $82 million compared with adjusted earnings of $313 million in the prior year comparable period. The adjusted earnings increase was supported by all segment assets, but primarily due to higher earnings from Enbridge System and the Southern Lights Pipeline.

While under construction, certain regulated pipelines are entitled to recognize AEDC in earnings. These amounts will be collected in tolls once the pipelines are in service. The earnings impact of AEDC for the Enbridge System was $1 million (2009 - $19 million) for the three months ended September 30, 2010 and $28 million (2009 - $49 million) for the nine months ended September 30, 2010, primarily related to Alberta Clipper. Recognition of AEDC on Alberta Clipper ceased following its in service date of April 1, 2010 when cash tolls commenced. There was no earnings impact of AEDC for the Southern Lights Pipeline for the three months ended September 30, 2010 (2009 - $9 million) as recognition of AEDC ceased following the in service date of July 1, 2010. The earnings impact of AEDC for the Southern Lights Pipeline was $32 million (2009 - $29 million) for the nine months ended September 30, 2010.

Factors positively impacting Enbridge System earnings in the three and nine month periods ended September 30, 2010 included cash tolls on Alberta Clipper entering service on April 1, 2010 and favourable operating performance. Earnings for the nine months ended September 30, 2010 also included AEDC.

During the second quarter of 2010, the NEB approved the Company s Enbridge System final toll submission filed in the first quarter of 2010, which includes a one year Incentive Tolling Settlement (ITS) agreement that can be extended into 2011. The ITS agreement allows for continued throughput protection on the Canadian mainline, increases the relative percentage of flow through costs and updates depreciation rates for certain pipeline assets, reducing the associated toll for shippers. Both the Line 9 NEB hearing scheduled for September 2010 and the Alberta Clipper NEB hearing scheduled for November 2010 have been suspended while the Company and the intervenors pursue settlement discussions. The Company and the shippers are in discussions over a long-term Canadian mainline tolling agreement.

Enbridge Regional Oil Sands System earnings increased as a result of higher volumes and increased tolls on certain laterals.

Higher Southern Lights Pipeline earnings reflected operating earnings from its in-service date of July 1, 2010 in addition to AEDC recognized on a growing capital base while the project was under construction during the first six months of 2010. This increase in earnings was partially offset by a decrease in earnings from the new light sour pipeline, which became operational during the first quarter of 2009 and was subsequently transferred to the Enbridge System effective May 1, 2010.

Spearhead Pipeline earnings for both the three and nine months ended September 30, 2010 increased compared with the corresponding periods of 2009 as a result of higher volumes resulting from the expansion completed in May 2009 as well as the recognition of make-up rights which expired in the period.

Feeder Pipelines and Other earnings increased due to improved operating results on a number of feeder systems and lower business development costs.

Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting item:

- Clean up and remediation costs related to a valve leak within the Enbridge Cheecham Terminal on the Enbridge Regional Oil Sands System in January 2009, which is not indicative of the expected future performance of this asset.

**NATURAL GAS DELIVERY AND SERVICES**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Enbridge Gas Distribution (EGD) | **(9)** | (17) | **89** | 76 |
| Noverco | **(4)** | (5) | **13** | 10 |
| Other Gas Distribution | **3** | 3 | **21** | 19 |
| Enbridge Offshore Pipelines (Offshore) | **7** | 8 | **21** | 19 |
| Alliance Pipeline US | **6** | 6 | **19** | 20 |
| Vector Pipeline | **3** | 3 | **11** | 12 |
| Aux Sable | **11** | 8 | **27** | 22 |
| Energy Services | **5** | (1) | **14** | 29 |
| Other | **-** | (3) | **(2)** | (2) |
| Adjusted Earnings | **22** | 2 | **213** | 205 |
| EGD - (warmer)/colder than normal weather | **-** | - | **(18)** | 14 |
| EGD - interest income on GST refund | **-** | - | **-** | 7 |
| Offshore - property insurance recoveries from hurricanes | **-** | - | **2** | 1 |
| Aux Sable - unrealized derivative fair value gains/(losses) | **(9)** | 5 | **5** | (11) |
| Energy Services - unrealized derivative fair value gains/(losses) | **(3)** | 8 | **(11)** | (3) |
| Energy Services - Lehman credit recovery | **-** | - | **1** | - |
| Other - gain on sale of investment in OCENSA | **-** | - | **-** | 329 |
| Other - adoption of new accounting standard | **-** | - | **-** | (3) |

| | | | | |
|---|---|---|---|---|
| Earnings | **10** | 15 | **192** | 539 |

Adjusted earnings from Natural Gas Delivery and Services were $22 million and $213 million for the three and nine months ended September 30, 2010 respectively, compared with $2 million and $205 million for the three and nine months ended September 30, 2009. The increase was primarily due to higher adjusted earnings in EGD. Adjusted earnings for the nine months ended September 30, 2010 also reflect weaker earnings contributions from the Company s Energy Services businesses.

The increase in EGD s adjusted earnings for both the third quarter and the first nine months of 2010 was primarily due to continued favourable performance under IR, reflecting customer growth and lower taxes, partially offset by higher accrued estimated customer earnings sharing and depreciation expense. Depreciation expense has increased due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

Within EGD, increased earnings in the third quarter of 2010 compared with 2009 included a positive variance of $6 million from higher fixed billings and corresponding lower variable charges. As there was an offsetting earnings decrease of $6 million in the first half of the year, there was no impact on year-to-date earnings. As initially reflected in the results for the first quarter of 2008, and in line with scheduled progressive changes contained in the five year IR terms, EGD s fixed charge billing per customer increased with a corresponding decrease in the per unit volumetric charge. These changes modify EGD s quarterly earnings profile relative to the prior year, but do not affect full year earnings as revenues are shifted from the colder winter quarters to the warmer summer quarters.

In September 2010, EGD filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. Subject to OEB approval, the resulting rate adjustment would be effective January 1, 2011.

Aux Sable adjusted earnings for the three and nine months ended September 30, 2010 increased compared with 2009 primarily due to enhanced plant performance, stronger fractionation margins and favourable risk management positions.

Energy Services adjusted earnings for the three months ended September 30, 2010 increased compared with the three months ended September 30, 2009 due to improved margin opportunities in natural gas marketing. Year-to-date Energy Services adjusted earnings decreased compared with 2009 due to reduced volume and margin opportunities in liquids marketing.

Natural Gas Delivery and Services earnings were impacted by the following non-recurring or non-operating adjusting items:

- EGD earnings are adjusted to reflect the impact of weather.
- Earnings from EGD for 2009 included interest income of $7 million related to the recovery of excess GST remitted to Canada Revenue Agency.
- Offshore earnings included insurance proceeds related to the replacement of damaged infrastructure as a result of the 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 included a $1 million partial recovery from the sale of the Company s receivable from Lehman Brothers previously written off.

- On March 17, 2009, the Company sold its investment in OCENSA, a crude oil export pipeline in Colombia, for proceeds of $512 million, resulting in a gain of $329 million.

- Other reflected the write-off of $3 million in deferred development costs as a result of adopting a change in accounting standards effective January 1, 2009.

**SPONSORED INVESTMENTS**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Enbridge Energy Partners (EEP) | **34** | 30 | **95** | 77 |
| Enbridge Energy, L.P. - Alberta Clipper US (EELP) | **14** | 1 | **32** | 1 |
| Enbridge Income Fund (EIF) | **11** | 11 | **34** | 34 |
| Adjusted Earnings | **59** | 42 | **161** | 112 |
| EEP - leak remediation costs and lost revenue | **(85)** | - | **(85)** | - |
| EEP - unrealized derivative fair value gains/(losses) | **(3)** | 1 | **2** | - |
| EEP - Lakehead System billing correction | **-** | - | **1** | 3 |
| EEP - dilution gain on Class A unit issuance | **3** | - | **4** | - |
| EEP - asset impairment loss | **(2)** | (12) | **(2)** | (12) |
| Earnings/(Loss) | **(28)** | 31 | **81** | 103 |

Sponsored Investments adjusted earnings were $59 million for the three months ended September 30, 2010 compared with $42 million for the three months ended September 30, 2009. For the nine months ended September 30, 2010, adjusted earnings were $161 million compared with $112 million in the comparable prior period.

After adjusting EEP earnings for non-recurring or non-operating items, including the impact of the Line 6B and 6A crude oil releases, EEP adjusted earnings increased largely attributable to strong results from the liquids business as well as higher incentive income. The liquids improvement was generated largely from higher delivered volumes, increased average transportation rates and higher allowance oil revenue, partially offset by increased power costs, operating costs and depreciation. The completion of Southern Access Expansion Phase II in April 2009, the North Dakota System Expansion that entered service on January 1, 2010 and the start up of the Alberta Clipper Project on April 1, 2010 contributed to the higher volumes and tariffs compared with the corresponding periods of 2009.

EELP Alberta Clipper US earnings represent the Company s earnings from its 66.7% investment in a series of equity within EELP which owns the United States segment of the Alberta Clipper Project. Earnings were attributable to AEDC recognized while the project was under construction as well as tolls since the Alberta Clipper Project went into service on April 1, 2010.

Sponsored Investments earnings for the three and nine months ended September 30, 2010 and 2009 were impacted by the following non-recurring or non-operating adjusting items:

- Earnings from EEP included a charge of $82 million (net to Enbridge) related to estimated costs, before insurance recoveries, associated with the Line 6B and 6A crude oil releases as well as a charge of $3 million (net to Enbridge) related to period lost revenue as a result of the leaks. These charges are not indicative of the future performance of this asset. Additional information about the Lakehead System Line 6B and 6A Leaks is included in Recent Developments.

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

- Earnings from EEP included Lakehead System billing corrections (net to Enbridge) related to services provided in prior periods.

- EEP earnings were favourably impacted by a dilution gain because Enbridge did not participate in EEP s Class A unit offerings.

- EEP earnings included asset impairment losses related to the write-down of certain assets.

**CORPORATE**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Adjusted Earnings/(Loss) | **(13)** | (10) | **(23)** | (14) |
| Unrealized derivative fair value gains/(losses) | **39** | 102 | **(23)** | 174 |
| Unrealized foreign exchange gains on translation of intercompany balances, net | **21** | 50 | **15** | 118 |
| Gain on sale of investment in NTP | **-** | - | **-** | 25 |
| Impact of tax rate changes | **-** | - | **-** | 6 |
| Earnings/(Loss) | **47** | 142 | **(31)** | 309 |

Corporate adjusted loss was $23 million for the nine months ended September 30, 2010 compared with $14 million for the nine months ended September 30, 2009, primarily reflecting increased financing costs, partially offset by contributions from the Sarnia Solar Project placed in service during the period.

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

- Earnings included the change in the unrealized fair value of derivative financial instruments related to forward foreign exchange risk management positions.

- Earnings included net unrealized foreign exchange gains on the translation of foreign-denominated intercompany balances.

- On May 1, 2009, the Company sold its investment in NTP, an internet-based crude oil trading and clearing platform, for proceeds of $32 million, resulting in a gain of $25 million.

- Earnings for the nine months ended September 30, 2009 reflected a $6 million benefit related to favourable legislated tax 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, 2010, excluding the Southern Lights project financing, the Company had $5,546 million of committed credit facilities of which $3,190 million was drawn or allocated to backstop commercial paper. In June 2010, the $100 million revolving credit agreement through which the Company provided liquidity support to the Company s affiliate EIF expired. In March 2010, the US$500 million revolving credit agreement through which the Company provided liquidity support to the Company s affiliate EEP was cancelled. As a result, the Company had net available liquidity at September 30, 2010 of $2,815 million, inclusive of unrestricted cash and cash equivalents of $459 million. The net available liquidity and selective capital markets funding are 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. During the year, the following transactions occurred:

- In September 2010, the Company secured additional credit facilities for Southern Lights to fund working capital requirements, increasing facilities by US$100 million and $50 million. The Company also cancelled unused credit and cost overrun facilities for the Southern Lights project financing, reducing facilities by US$151 million and $22 million.

- In August 2010, the Company secured a new credit facility, increasing available credit by $750 million.

- In July 2010, the Company reduced available credit under an existing Natural Gas Delivery and Services credit facility by $100 million to $700 million.

- In June 2010, the Company reduced available credit under an existing credit facility to $350 million, decreasing available credit in Liquids Pipelines by $650 million. The Company subsequently cancelled the remaining portion of this credit facility.

- In May 2010, the Company reduced an existing facility, decreasing credit facilities in Liquids Pipelines by $100 million.

The following table provides details of the Company s credit facilities at September 30, 2010.

| *(millions of Canadian dollars)* | Expiry Dates | Total Facilities | Credit Facility Draws[2] | Available |
|---|---|---|---|---|
| Liquids Pipelines | **2012** | **200** | **26** | **174** |
| Natural Gas Delivery and Services | **2010-2012** | **712** | **441** | **271** |
| Corporate | **2012-2014** | **4,634** | **2,723** | **1,911** |
| | | **5,546** | **3,190** | **2,356** |
| Southern Lights project financing[1] | **2012-2014** | **1,750** | **1,551** | **199** |
| Credit Facilities | | **7,296** | **4,741** | **2,555** |

1. Total facilities inclusive of $61 million for debt service reserve letters of credit.

2. Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

**OPERATING ACTIVITIES**

Cash from operating activities was $319 million and $1,476 million for the three and nine months ended September 30, 2010, respectively, compared with $244 million and $1,835 million for the three and nine months ended September 30, 2009. Cash from operating activities was positively impacted in 2010 by contributions from growth projects placed in service, including Alberta Clipper and Southern Lights Pipeline. Alberta Clipper includes contributions from both the Canadian portion as well as cash distributions received on the Company s 66.7% equity investment in EELP which owns the United States segment of Alberta Clipper. For both the three and nine months ended September 30, 2010, variances in working capital balances, primarily due to changes in natural gas prices at EGD, resulted in period-over-period declines in cash from operating activities.

There are no material restrictions on the Company s cash with the exception of proportionately consolidated joint venture cash of $70 million, which cannot be accessed until distributed to the Company, and cash in trust of $11 million for specific shipper commitments.

**INVESTING ACTIVITIES**

Cash used in investing activities for the three and nine months ended September 30, 2010 was $741 million and $1,928 million, respectively, compared with $1,293 million and $2,144 million for the three and nine months ended September 30, 2009. Cash used in investing activities included $698 million (2009 - $930 million) and $1,563 million (2009 - $2,280 million) of additions to property plant and equipment for the three and nine months ended September 30, 2010, respectively. Additions to property, plant and equipment have declined compared with 2009 given the completion of several significant projects - Alberta Clipper, Southern Lights Pipeline and Hardisty Contract Terminal, among others. The Company completed two acquisitions in the first nine months of

2010 resulting in a use of cash of $64 million. Investing activities also included long-term investments and affiliate lending, primarily the Company s investing in and funding of EELP which holds the Company s interest in the United States segment of Alberta Clipper. The higher use of cash used in investing activities reported in 2009 was partially offset by proceeds received on the sale of the Company s investments in OCENSA and NTP.

**FINANCING ACTIVITIES**

Cash generated from financing activities for the three and nine months ended September 30, 2010 was $490 million and $597 million, respectively, compared with $1,113 million and $197 million for the three and nine months ended September 30, 2009. The increase in cash for the nine months ended September 30, 2010 compared with 2009 primarily resulted from medium-term note issuances of $500 million in

March 2010, $650 million in April 2010, and $550 million in September 2010. The proceeds from these term note issuances were used in part to fund term note repayments of $450 million and net commercial paper and credit facility repayments of $368 million.

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, 2010, dividends declared were $163 million (2009 - $139 million), of which $107 million (2009 - $102 million) were paid in cash and reflected in financing activities. The remaining $56 million (2009 - $37 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, 2010, dividends declared were $485 million (2009 - $416 million), of which $316 million (2009 - $312 million) were paid in cash and reflected in financing activities. The remaining $169 million (2009 - $104 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, 2010, 34% (2009 - 27%) and 35% (2009 - 25%) of total dividends declared were reinvested.

On November 2, 2010, the Enbridge Board of Directors declared quarterly dividends of $0.425 per common share and $0.34375 per Series A Preferred Share. Both dividends are payable on December 1, 2010 to shareholders of record on November 15, 2010.

**Capital Expenditure Commitments**

The Company has signed contracts for the purchase of services, pipe and other materials totaling $1,132 million which are expected to be paid over the next five years.

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project through EEP and EELP. The total cost of the United States segment was US$1,200 million. As at September 30, 2010, the Company had substantially met all funding commitments.

## CRITICAL ACCOUNTING ESTIMATES

### ASSET RETIREMENT OBLIGATIONS

In 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 the end of May 2014. In March 2010, the NEB issued a report revising certain base case assumptions and, as such, large pipeline companies are required to file abandonment cost estimates by May 2011. The NEB is requiring large pipeline companies to file a proposed process for collecting and setting aside the funds for abandonment by May 2012. Both of the required submissions will need 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 scope of the asset retirements. However, should the NEB action plan result in a reasonable estimate of asset retirement obligations for accounting purposes, financial statement recognition of these amounts may be made in future periods.

## FUTURE ACCOUNTING POLICIES

In February 2008, the Canadian Accounting Standards Board (AcSB) determined that International Financial Reporting Standards (IFRS) will become the new Canadian accounting standards for publicly accountable entities for periods beginning on or after January 1, 2011. In July 2010, the AcSB issued an Exposure Draft which would have allowed qualifying entities with rate regulated activities an optional two year deferral to adopt IFRS and would have permitted such entities to continue to apply the accounting standards in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook during that period. Subsequently, in October 2010, the AcSB finalized its amendments to the CICA Handbook regarding the adoption of IFRS, stating the first-time adoption of IFRS for qualifying entities with rate regulated activities is mandatory effective January 1, 2012, which reduced the two year deferral period to one year. Enbridge is a qualifying entity for purposes of this deferral.

While the Company s IFRS conversion project was on track to meet the original conversion deadline, the Company has elected to use the one year deferral offered by the AcSB. This decision was made given the continuing uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business model and performance measurement. The International Accounting Standards Board (IASB) originally issued an exposure draft on Rate Regulated Activities in 2009 but has since failed to finalize the accounting standard or provide definitive guidance on the direction of the project.

As a United States Securities and Exchange Commission registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP. During the 2011 deferral period, the Company will present its financial statements in accordance with Part V of the CICA Handbook, continue to closely monitor developments of the IASB, and determine whether IFRS or U.S. GAAP would provide the most useful and reliable presentation of its financial results for 2012 and future periods.

## QUARTERLY FINANCIAL INFORMATION[1]

| *(millions of Canadian dollars, except per share amounts)* | | **2010** | | | 2009 | | | 2008 |
|---|---|---|---|---|---|---|---|---|
| | **Q3** | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 |
| Revenues | **3,502** | 3,505 | 3,977 | 3,186 | 2,629 | 2,868 | 3,783 | 3,924 |
| Earnings applicable to common shareholders | **157** | 138 | 342 | 300 | 304 | 393 | 558 | 264 |
| Earnings per common share | **0.42** | 0.37 | 0.93 | 0.81 | 0.83 | 1.08 | 1.54 | 0.72 |
| Diluted earnings per common share | **0.42** | 0.37 | 0.92 | 0.80 | 0.83 | 1.08 | 1.53 | 0.71 |
| Dividends per common share | **0.425** | 0.425 | 0.425 | 0.370 | 0.370 | 0.370 | 0.370 | 0.330 |

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

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, including the impact of AEDC recognized during the construction period.

Revenues include amounts billed to customers of EGD for natural gas, which varies with fluctuations in the commodity price and seasonal heating demand. Higher natural gas commodity prices increase revenues but would not similarly impact earnings as the cost of natural gas flows through to customers. Fluctuations in commodity prices impact revenues, costs and earnings from Energy Services businesses.

Significant items that impacted the quarterly earnings and revenues were as follows:

- Third quarter 2010 earnings reflect the recognition of leak remediation costs, before insurance recoveries, and lost revenues associated with the Lakehead System Line 6B and 6A crude oil releases, partially offset by unrealized fair value gains on derivative financial instruments used to manage foreign exchange risk and unrealized foreign exchange gains on translation of intercompany balances.

- Second quarter 2010 earnings reflect the recognition of unrealized fair value losses on derivative financial instruments used to manage foreign exchange risk, partially offset by increased earnings as a result of higher volumes and tariffs on certain assets.

- First quarter 2010 earnings reflect unrealized fair value losses and gains on derivative financial instruments used to manage commodity price risk and foreign exchange rate risk, respectively.

• Fourth quarter 2009 earnings reflect decreased revenues from gas distribution businesses due to depressed natural gas prices throughout 2009 and unrealized fair value gains on derivative financial instruments used to manage commodity price risk and foreign exchange rate risk.

• Third quarter 2009 earnings reflect AEDC in Liquids Pipelines as well as unrealized fair value gains on derivative financial instruments used to risk manage foreign exchange and interest rate variability.

• Second quarter 2009 earnings reflect a higher contribution from EEP, AEDC in Liquids Pipelines as well as unrealized fair value gains on derivative financial instruments used to risk manage commodity, foreign exchange and interest rate variability.

• First quarter 2009 earnings reflect a gain of $329 million on the disposition of the Company s investment in OCENSA. Revenues decreased due to lower average commodity prices relative to 2008.

• Fourth quarter earnings in 2008 reflect AEDC in Liquids Pipelines, a higher contribution from EGD and unrealized fair value gains on derivative financial instruments in Aux Sable and Energy Services.

**NON-GAAP RECONCILIATIONS**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| GAAP earnings as reported | **157** | 304 | **637** | 1,255 |
| Significant after-tax non-recurring or non-operating factors and variances: | | | | |
| Liquids Pipelines | | | | |
| Enbridge Regional Oil Sands System - leak remediation costs | **-** | 3 | **-** | 9 |
| Natural Gas Delivery and Services | | | | |
| EGD - warmer/(colder) than normal weather | **-** | - | **18** | (14) |
| EGD - interest income on GST refund | **-** | - | **-** | (7) |
| Offshore - property insurance recoveries from hurricanes | **-** | - | **(2)** | (1) |
| Aux Sable - unrealized derivative fair value (gains)/losses | **9** | (5) | **(5)** | 11 |
| Energy Services - unrealized derivative fair value (gains)/losses | **3** | (8) | **11** | 3 |
| Energy Services Lehman credit recovery | **-** | - | **(1)** | - |
| Other - gain on sale of investment in OCENSA | **-** | - | **-** | (329) |
| Other - adoption of new accounting standard | **-** | - | **-** | 3 |
| Sponsored Investments | | | | |
| EEP - leak remediation costs and lost revenue | **85** | - | **85** | - |
| EEP - unrealized derivative fair value (gains)/losses | **3** | (1) | **(2)** | - |
| EEP - Lakehead System billing correction | **-** | - | **(1)** | (3) |
| EEP - dilution gain on Class A unit issuance | **(3)** | - | **(4)** | - |
| EEP - asset impairment loss | **2** | 12 | **2** | 12 |
| Corporate | | | | |
| Unrealized derivative fair value (gains)/losses | **(39)** | (102) | **23** | (174) |
| Unrealized foreign exchange gains on translation of intercompany balances, net | **(21)** | (50) | **(15)** | (118) |
| Gain on sale of investment in NTP | **-** | - | **-** | (25) |
| Impact of tax rate changes | **-** | - | **-** | (6) |
| Adjusted Earnings | **196** | 153 | **746** | 616 |

## OUTSTANDING SHARE DATA

| | Number |
|---|---|
| Preferred Shares, Series A (non-voting equity shares) | 5,000,000 |
| Common Shares - issued and outstanding (voting equity shares) | 383,939,669 |
| Stock Options - issued and outstanding (7,921,062 vested) | 15,460,997 |

Outstanding share data information is provided as at October 26, 2010.

# ENBRIDGE INC.

# CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

**September 30, 2010**

# CONSOLIDATED STATEMENTS OF EARNINGS

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| Revenues | | | | |
| Commodity sales | **2,725** | 1,963 | **8,710** | 7,229 |
| Transportation and other services | **777** | 666 | **2,274** | 2,051 |
| | **3,502** | 2,629 | **10,984** | 9,280 |
| Expenses | | | | |
| Commodity costs | **2,596** | 1,829 | **8,221** | 6,721 |
| Operating and administrative | **366** | 334 | **1,049** | 1,043 |
| Depreciation and amortization | **214** | 191 | **612** | 562 |
| | **3,176** | 2,354 | **9,882** | 8,326 |
| | **326** | 275 | **1,102** | 954 |
| Income/(Loss) from Equity Investments | **(135)** | 26 | **22** | 138 |
| Other Income | **125** | 256 | **177** | 543 |
| Interest Expense | **(185)** | (150) | **(508)** | (431) |
| Gain on Sale of Investments *(Note 2)* | **-** | - | **-** | 365 |
| | **131** | 407 | **793** | 1,569 |
| Non-Controlling Interests | **28** | (7) | **2** | (28) |
| | **159** | 400 | **795** | 1,541 |
| Income Taxes | **(1)** | (95) | **(153)** | (281) |
| Earnings | **158** | 305 | **642** | 1,260 |
| Preferred Share Dividends | **(1)** | (1) | **(5)** | (5) |
| Earnings Applicable to Common Shareholders | **157** | 304 | **637** | 1,255 |
| Earnings per Common Share | **0.42** | 0.83 | **1.73** | 3.45 |
| Diluted Earnings per Common Share | **0.42** | 0.83 | **1.71** | 3.43 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Earnings | **158** | 305 | **642** | 1,260 |
| Other Comprehensive Loss | | | | |
| Change in unrealized loss on cash flow hedges, net of tax | **(54)** | (57) | **(166)** | (122) |
| Change in unrealized gain on net investment hedges, net of tax | **35** | 72 | **3** | 137 |
| Reclassification to earnings of realized cash flow hedges, net of tax | **(57)** | 20 | **(26)** | 110 |
| Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 2)* | **-** | - | **-** | (20) |
| Other comprehensive loss from equity investees, net of tax | **(11)** | (13) | **(24)** | (26) |
| Non-controlling interests in other comprehensive income | **19** | 40 | **24** | 68 |
| Change in foreign currency translation adjustment | **(162)** | (395) | **(84)** | (692) |
| Other Comprehensive Loss | **(230)** | (333) | **(273)** | (545) |
| Comprehensive Income/(Loss) | **(72)** | (28) | **369** | 715 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

| | Nine months ended September 30, | |
|---|---|---|
| *(unaudited; millions of Canadian dollars, except per share amounts)* | **2010** | 2009 |
| Preferred Shares | **125** | 125 |
| Common Shares | | |
| Balance at beginning of period | **3,379** | 3,194 |
| Common shares issued | **-** | 4 |
| Dividend reinvestment and share purchase plan | **169** | 104 |
| Shares issued on exercise of stock options | **64** | 21 |
| Balance at End of Period | **3,612** | 3,323 |
| Contributed Surplus | | |
| Balance at beginning of period | **54** | 38 |
| Stock-based compensation | **10** | 16 |
| Options exercised | **(5)** | (1) |
| Balance at End of Period | **59** | 53 |
| Retained Earnings | | |
| Balance at beginning of period | **4,400** | 3,384 |
| Earnings applicable to common shareholders | **637** | 1,255 |
| Common share dividends declared | **(485)** | (416) |
| Dividends paid to reciprocal shareholder | **14** | 12 |
| Balance at End of Period | **4,566** | 4,235 |
| Accumulated Other Comprehensive Income/(Loss) | | |
| Balance at beginning of period | **(543)** | 33 |
| Other comprehensive loss | **(273)** | (545) |
| Balance at End of Period | **(816)** | (512) |
| Reciprocal Shareholding | **(154)** | (154) |
| Total Shareholders Equity | **7,392** | 7,070 |
| Dividends Paid per Common Share | **1.275** | 1.110 |

*See accompanying notes to the unaudited consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| *(unaudited; millions of Canadian dollars)* | Three months ended September 30, 2010 | 2009 | Nine months ended September 30, 2010 | 2009 |
|---|---|---|---|---|
| Operating Activities | | | | |
| Earnings | **158** | 305 | **642** | 1,260 |
| Depreciation and amortization | **214** | 191 | **612** | 562 |
| Unrealized losses/(gains) on derivative instruments | **(27)** | (153) | **56** | (202) |
| Allowance for equity funds used during construction | **(1)** | (33) | **(79)** | (94) |
| Cash distributions in excess of equity earnings | **209** | 18 | **152** | - |
| Gain on sale of investments | **-** | - | **-** | (365) |
| Gain on reduction of ownership interest | **(6)** | - | **(8)** | - |
| Future income taxes | **8** | 72 | **121** | 112 |
| Non-controlling interests | **(28)** | 7 | **(2)** | 28 |
| Other | **(19)** | (58) | **1** | (89) |
| Changes in operating assets and liabilities | **(189)** | (105) | **(19)** | 623 |
| | **319** | 244 | **1,476** | 1,835 |
| Investing Activities | | | | |
| Acquisitions *(Note 3)* | **(12)** | - | **(64)** | - |
| Long-term investments | **(11)** | (223) | **(104)** | (225) |
| Affiliate loans, net | **(7)** | (178) | **(81)** | (178) |
| Proceeds on sale of investments *(Note 2)* | **-** | - | **-** | 535 |
| Sale of property, plant and equipment | **-** | - | **-** | 87 |
| Settlement of hedges *(Note 2)* | **-** | - | **-** | 6 |
| Additions to property, plant and equipment | **(698)** | (930) | **(1,563)** | (2,280) |
| Additions to intangible assets | **(21)** | (15) | **(38)** | (53) |
| Change in construction payable | **8** | 53 | **(78)** | (36) |
| | **(741)** | (1,293) | **(1,928)** | (2,144) |
| Financing Activities | | | | |
| Net change in short-term borrowings | **282** | 354 | **(74)** | (520) |
| Net change in commercial paper and credit facility draws | **(273)** | 276 | **(368)** | 324 |
| Debenture and term note issues | **550** | 600 | **1,700** | 1,000 |
| Debenture and term note repayments | **-** | - | **(450)** | (416) |
| Net change in Southern Lights project financing | **(29)** | - | **22** | 190 |
| Non-recourse debt issues | **35** | - | **142** | - |
| Non-recourse debt repayments | **(13)** | (10) | **(101)** | (48) |
| Contributions from/(distributions to) non-controlling interests | **17** | (10) | **(6)** | (35) |
| Common shares issued | **29** | 6 | **53** | 19 |
| Preferred share dividends | **(1)** | (1) | **(5)** | (5) |
| Common share dividends | **(107)** | (102) | **(316)** | (312) |
| | **490** | 1,113 | **597** | 197 |
| Effect of translation of foreign denominated cash and cash equivalents | **(7)** | (14) | **(2)** | (25) |
| Increase/(Decrease) in Cash and Cash Equivalents | **61** | 50 | **143** | (137) |
| Cash and Cash Equivalents at Beginning of Period | **409** | 355 | **327** | 542 |
| Cash and Cash Equivalents at End of Period[1] | **470** | 405 | **470** | 405 |

*See accompanying notes to the unaudited consolidated financial statements.*

1. Cash and cash equivalents consists of $272 million (2009 - $175 million) of cash and $198 million (2009 - $230 million) of short-term investments which includes restricted cash of $11 million (2009 - $18 million).

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| *(unaudited; millions of Canadian dollars)* | **September 30, 2010** | December 31, 2009 |
|---|---|---|
| **Assets** | | |
| Current Assets | | |
| Cash and cash equivalents | **470** | 327 |
| Accounts receivable and other | **2,024** | 2,484 |
| Inventory | **798** | 784 |
| | **3,292** | 3,595 |
| Property, Plant and Equipment, net | **19,919** | 18,850 |
| Long-Term Investments | **2,213** | 2,312 |
| Deferred Amounts and Other Assets | **2,722** | 2,425 |
| Intangible Assets | **481** | 488 |
| Goodwill | **387** | 372 |
| Future Income Taxes | **80** | 127 |
| | **29,094** | 28,169 |
| **Liabilities and Shareholders Equity** | | |
| Current Liabilities | | |
| Short-term borrowings | **434** | 508 |
| Accounts payable and other | **2,136** | 2,463 |
| Interest payable | **144** | 104 |
| Current maturities of long-term debt | **304** | 601 |
| Current maturities of non-recourse long-term debt | **93** | 113 |
| | **3,111** | 3,789 |
| Long-Term Debt | **12,750** | 11,581 |
| Non-Recourse Long-Term Debt | **1,445** | 1,393 |
| Other Long-Term Liabilities | **1,426** | 1,207 |
| Future Income Taxes | **2,264** | 2,211 |
| | **20,996** | 20,181 |
| Non-Controlling Interests | **706** | 727 |
| Shareholders Equity | | |
| Share capital | | |
| Preferred shares | **125** | 125 |
| Common shares | **3,612** | 3,379 |
| Contributed surplus | **59** | 54 |
| Retained earnings | **4,566** | 4,400 |
| Accumulated other comprehensive loss | **(816)** | (543) |
| Reciprocal shareholding | **(154)** | (154) |
| | **7,392** | 7,261 |
| Commitments and Contingencies *(Note 6)* | | |
| | **29,094** | 28,169 |

*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 Canadian generally accepted accounting principles (Canadian GAAP). 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 2009 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 8. 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 2009 Annual Report.

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. SEGMENTED INFORMATION

| **Three months ended September 30, 2010** | Liquids Pipelines | Natural Gas Delivery and Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | |
| Revenues | **456** | **2,950** | **81** | **15** | **3,502** |
| Commodity costs | **-** | **(2,596)** | **-** | **-** | **(2,596)** |
| Operating and administrative | **(157)** | **(169)** | **(30)** | **(10)** | **(366)** |
| Depreciation and amortization | **(77)** | **(107)** | **(22)** | **(8)** | **(214)** |
| | **222** | **78** | **29** | **(3)** | **326** |
| Income/(loss) from equity investments | **-** | **(8)** | **(127)** | **-** | **(135)** |
| Other income | **13** | **20** | **16** | **76** | **125** |
| Interest and preferred share dividends | **(67)** | **(65)** | **(13)** | **(41)** | **(186)** |
| Non-controlling interests | **(1)** | **(2)** | **31** | **-** | **28** |
| Income taxes | **(39)** | **(13)** | **36** | **15** | **(1)** |
| Earnings applicable to common shareholders | **128** | **10** | **(28)** | **47** | **157** |

| Three months ended September 30, 2009 | Liquids Pipelines | Natural Gas Delivery and Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | | | | | |
| Revenues | 339 | 2,203 | 79 | 8 | 2,629 |
| Commodity costs | - | (1,829) | - | - | (1,829) |
| Operating and administrative | (139) | (160) | (29) | (6) | (334) |
| Depreciation and amortization | (60) | (101) | (23) | (7) | (191) |
| | 140 | 113 | 27 | (5) | 275 |
| Income/(loss) from equity investments | - | (10) | 36 | - | 26 |
| Other income | 43 | 5 | 4 | 204 | 256 |
| Interest and preferred share dividends | (28) | (62) | (13) | (48) | (151) |
| Non-controlling interests | (1) | (2) | (4) | - | (7) |
| Income taxes | (38) | (29) | (19) | (9) | (95) |
| Earnings applicable to common shareholders | 116 | 15 | 31 | 142 | 304 |

| **Nine months ended September 30, 2010**<br>*(unaudited; millions of Canadian dollars)* | Liquids Pipelines | Natural Gas Delivery and Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|
| Revenues | **1,194** | **9,508** | **239** | **43** | **10,984** |
| Commodity costs | **-** | **(8,221)** | **-** | **-** | **(8,221)** |
| Operating and administrative | **(431)** | **(511)** | **(86)** | **(21)** | **(1,049)** |
| Depreciation and amortization | **(207)** | **(316)** | **(64)** | **(25)** | **(612)** |
| | **556** | **460** | **89** | **(3)** | **1,102** |
| Income from equity investments | **-** | **2** | **20** | **-** | **22** |
| Other income | **108** | **23** | **35** | **11** | **177** |
| Interest and preferred share dividends | **(163)** | **(190)** | **(41)** | **(119)** | **(513)** |
| Non-controlling interests | **(2)** | **(5)** | **9** | **-** | **2** |
| Income taxes | **(104)** | **(98)** | **(31)** | **80** | **(153)** |
| Earnings applicable to common shareholders | **395** | **192** | **81** | **(31)** | **637** |

| Nine months ended September 30, 2009<br>*(unaudited; millions of Canadian dollars)* | Liquids Pipelines | Natural Gas Delivery and Services | Sponsored Investments | Corporate | Consolidated |
|---|---|---|---|---|---|
| Revenues | 973 | 8,045 | 231 | 31 | 9,280 |
| Commodity costs | - | (6,720) | - | (1) | (6,721) |
| Operating and administrative | (423) | (515) | (81) | (24) | (1,043) |
| Depreciation and amortization | (169) | (307) | (65) | (21) | (562) |
| | 381 | 503 | 85 | (15) | 954 |
| Income/(loss) from equity investments | - | (1) | 139 | - | 138 |
| Other income and gain on sale of investments | 113 | 362 | 9 | 424 | 908 |
| Interest and preferred share dividends | (106) | (190) | (42) | (98) | (436) |
| Non-controlling interests | (2) | (5) | (20) | (1) | (28) |
| Income taxes | (82) | (130) | (68) | (1) | (281) |
| Earnings applicable to common shareholders | 304 | 539 | 103 | 309 | 1,255 |

**ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT**[1]

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Liquids Pipelines | **154** | 827 | **573** | 2,041 |
| Natural Gas Delivery and Services | **79** | 109 | **263** | 299 |
| Sponsored Investments | **44** | 13 | **81** | 20 |
| Corporate | **422** | 14 | **725** | 14 |
| | **699** | 963 | **1,642** | 2,374 |

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

## 2. GAIN ON SALE OF INVESTMENTS

**NetThruPut**

On May 1, 2009, the Company sold its investment in NetThruPut (NTP), an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment were nil and $1 million for the three and nine months ended September 30, 2009, respectively, and are included in the Corporate operating segment.

**OCENSA**

On March 17, 2009, the Company sold its investment in Oleoducto Central S.A. (OCENSA), a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the three and nine months ended September 30, 2009 were nil and $7 million. Earnings from the OCENSA investment are included in the Natural Gas Delivery and Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from Other Comprehensive Income (OCI) to earnings. Cash provided by the settlement of OCENSA currency hedges was nil and $6 million for the three and nine months ended September 30, 2009, respectively.

## 3. ACQUISITIONS

On August 9, 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic), 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. 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 Pipelines segment.

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (HCLP), 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 HCLP. Prior to June 16, 2010, the entity was accounted for as a joint venture. The Company s interest in HCLP continues to be held within the Liquids Pipelines segment.

## 4. RISK MANAGEMENT

The Company is exposed to cash flow and revaluation risk due to the volatility of interest rates. In August 2010, the Company entered into additional derivative instruments to mitigate cash flow volatility due to the effect of future interest rate fluctuations on current and anticipated debt issuances. The total notional principle of interest rate derivative instruments outstanding at September 30, 2010 is $6,816 million (December 31, 2009 - $6,022 million). At September 30, 2010, the Company had a net derivative liability of $241 million (December 31, 2009 - net asset of $43 million) related to interest rate derivative instruments.

At September 30, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have had no impact to earnings (December 31, 2009 - $2 million increase) and a $213 million (December 31, 2009 - $197 million) increase in OCI in the period due to the revaluation of interest rate derivatives outstanding at September 30, 2010. Further, there would have been a $22 million (December 31, 2009 - $26 million) decrease in earnings due to increased interest expense related to the Company s variable rate debt outstanding at September 30, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

## 5. POST EMPLOYMENT BENEFITS

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Natural Gas Delivery and Services 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 post-employment benefits other than pensions (OPEB) for qualifying retired employees. Costs related to the period are presented below.

### NET PENSION PLAN AND OPEB COSTS

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | **2010** | 2009 | **2010** | 2009 |
| Benefits earned during the period | **14** | 14 | **42** | 45 |
| Interest cost on projected benefit obligations | **20** | 20 | **61** | 61 |
| Expected return on plan assets | **(20)** | (20) | **(61)** | (60) |
| Amortization of unrecognized amounts | **5** | 6 | **15** | 17 |
| Amount charged to Enbridge Energy Partners, L.P. | **(4)** | (5) | **(14)** | (18) |
| Pension and OPEB Costs | **15** | 15 | **43** | 45 |

The table reflects the pension and OPEB cost for all the Company s benefit plans on an accrual basis. For costs related to the Natural Gas Delivery and Services pension and OPEB plans, no earnings impact resulted as offsetting long-term regulatory assets and liabilities have been recorded as plan contributions and actual OPEB benefit costs are recovered through rates.

## 6. COMMITMENTS AND CONTINGENCIES

### COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $1,132 million which are expected to be paid within the next five years.

### 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 the appeal was heard by the Superior Court during November and December 2009. On April 14, 2010, the Superior Court overturned the trial judge s decision and ordered a new trial to be conducted before a different judge. EGD has commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. The Court of Appeal has not yet issued its decision on EGD s motion. Management does not believe any fines that may be levied will have a material financial impact on the Company.

**ENBRIDGE ENERGY PARTNERS, L.P.**

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

Enbridge s exposure to the Line 6B and 6A leaks results from its approximate 27% combined direct and indirect ownership interest in Enbridge Energy Partners, L.P. (EEP), which is accounted for as an equity investment, and EEP s leak remediation costs and lost revenues.

*Line 6B Leak*

On July 26, 2010, EEP confirmed a crude oil release on Line 6B of its Lakehead System near Marshall, Michigan. EEP estimated 19,500 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. Regulatory approval of the pipeline restart plan was obtained from the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA) and, on September 27, 2010, the pipeline was safely brought back into service. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

EEP currently estimates that before insurance recoveries, and not including fines and penalties, costs of approximately US$430 million ($75 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), will be incurred in connection with this incident. These costs include emergency response, environmental remediation and cleanup activities associated with the crude oil release and related pipeline inspection costs. Actual costs incurred may differ from the estimate due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

*Line 6A Leak*

A crude oil release from Line 6A of EEP s Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP currently estimates that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release and related pipeline inspection will be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge). Actual costs incurred may differ from the estimate due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

*Insurance Recoveries*

EEP maintains commercial liability insurance coverage that includes a per incident deductible of approximately US$5 million, excluding fines and penalties, and limits of coverage that are expected to be sufficient to fund the costs and liabilities resulting from the leaks from Lines 6A and 6B. Apart from approximately US$16 million in lost revenues, which is non recoverable as EEP does not maintain insurance coverage for interruption of operations except for water crossings, it is anticipated that substantially all of the costs incurred from the leaks will ultimately be recoverable under EEP s existing insurance policies. EEP expects to record a receivable for any amounts claimed for recovery pursuant to its insurance policies during the period realization of the claim for recovery is deemed probable.

*Pipeline Integrity Commitment*

In connection with the restart of Line 6B, EEP committed to accelerate a process, initiated prior to the leak, to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, EEP will remediate ahead of its original schedule those pipeline anomalies it previously identified between 2007 and 2009 that were scheduled for refurbishment, including anomalies identified for action in a July 2010 PHMSA notification. EEP has agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. 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. The total cost to EEP for these integrity measures and pipeline replacement are estimated to approximate US$110 million, the majority of which is expected to be capital in nature. Additional significant integrity expenditures may be required after this initial remediation program. EEP is currently discussing with its customers recovery of these costs through the tolls on its Lakehead System.

*Legal and Regulatory Proceedings*

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B incidents. Currently, eight actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6 B incident; however, currently no penalties or fines have been assessed against EEP in connection with this incident. Currently, one action or claim related to the Line 6A incident has been filed against Enbridge, EEP or their affiliates in United States federal and state courts. The Company believes this action or claim has been resolved pursuant to an agreed interim order.

**OTHER TAX MATTERS**

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

**OTHER LITIGATION**

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

## 7. RELATED PARTY TRANSACTIONS

In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, Enbridge Energy Partners L.P., to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $7 million for the three and nine months ended September 30, 2010.

## 8. 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/(LOSS)

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| Earnings under Canadian GAAP Applicable to Common Shareholders | **157** | 304 | **637** | 1,255 |
| Earnings under Canadian GAAP | **158** | 305 | **642** | 1,260 |
| Dilution gains, net of tax[1] | **(4)** | - | **(5)** | - |
| Gain on acquisition, net of tax [2] | **-** | - | **20** | - |
| Inventory valuation adjustment, net of tax[3] | **(2)** | 10 | **21** | (9) |
| Earnings/(Loss) attributable to non-controlling interests | | | | |
| EEP[4] | **(272)** | 26 | **(128)** | 148 |
| Other[1,5] | **(27)** | 7 | **(1)** | 28 |
| Earnings/(Loss) under U.S. GAAP | **(147)** | 348 | **549** | 1,427 |
| Attributable to | | | | |
| Enbridge Inc.[5] | **152** | 315 | **678** | 1,251 |
| Non-controlling interests[5] | **(299)** | 33 | **(129)** | 176 |
| Earnings/(Loss) under U.S. GAAP | **(147)** | 348 | **549** | 1,427 |
| Earnings per Common Share attributable to Enbridge Inc. | **0.41** | 0.86 | **1.84** | 3.44 |
| Diluted Earnings per Common Share attributable to Enbridge Inc. | **0.41** | 0.86 | **1.82** | 3.42 |

### COMPREHENSIVE INCOME

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars, except per share amounts)* | **2010** | 2009 | **2010** | 2009 |
| Earnings/(Loss) under U.S. GAAP | **(147)** | 348 | **549** | 1,427 |
| Other comprehensive loss under Canadian GAAP | **(230)** | (333) | **(273)** | (545) |
| Underfunded pension adjustment, net of tax[6] | **23** | - | **(3)** | (27) |
| Other comprehensive income attributable to non-controlling interests under Canadian GAAP[5] | **(19)** | (40) | **(24)** | (68) |
| Other comprehensive loss attributable to non-controlling interests in EEP under U.S. GAAP[4] | **(35)** | (28) | **(65)** | (83) |
| Comprehensive Income/(Loss) under U.S. GAAP | **(408)** | (53) | **184** | 704 |
| Attributable to | | | | |
| Enbridge Inc.[5] | **(55)** | (18) | **402** | 679 |
| Non-controlling interests[5] | **(353)** | (35) | **(218)** | 25 |
| Comprehensive Income/(Loss) under U.S. GAAP | **(408)** | (53) | **184** | 704 |

**FINANCIAL POSITION**

| | **September 30, 2010** | | December 31, 2009 | |
|---|---|---|---|---|
| *(unaudited; millions of Canadian dollars)* | **Canada** | **United States** | Canada | United States |
| **Assets** | | | | |
| Current Assets | | | | |
| Cash and cash equivalents4,7 | **470** | **693** | 327 | 478 |
| Accounts receivable and other4,7 | **2,024** | **2,678** | 2,484 | 2,848 |
| Inventory3,4,7 | **798** | **948** | 784 | 824 |
| | **3,292** | **4,319** | 3,595 | 4,150 |
| Property, Plant and Equipment, net4,7 | **19,919** | **28,637** | 18,850 | 26,837 |
| Long-Term Investments4,7 | **2,213** | **224** | 2,312 | 228 |
| Deferred Amounts and Other Assets4,6,7,8 | **2,722** | **2,057** | 2,425 | 2,478 |
| Intangible Assets4 | **481** | **764** | 488 | 575 |
| Goodwill2,4 | **387** | **740** | 372 | 719 |
| Future Income Taxes7 | **80** | **99** | 127 | 148 |
| | **29,094** | **36,840** | 28,169 | 35,135 |
| **Liabilities and Shareholders Equity** | | | | |
| Current Liabilities | | | | |
| Short-term borrowings | **434** | **434** | 508 | 508 |
| Accounts payable and other4,7 | **2,136** | **3,180** | 2,463 | 3,178 |
| Interest payable4 | **144** | **224** | 104 | 151 |
| Current maturities of long-term debt4 | **304** | **336** | 601 | 633 |
| Current maturities of non-recourse long-term debt7 | **93** | **93** | 113 | 131 |
| | **3,111** | **4,267** | 3,789 | 4,601 |
| Long-Term Debt4,7,8 | **12,750** | **17,831** | 11,581 | 15,647 |
| Non-Recourse Long-Term Debt7 | **1,445** | **1,131** | 1,393 | 1,399 |
| Other Long-Term Liabilities4,6,7 | **1,426** | **1,631** | 1,207 | 1,311 |
| Future Income Taxes2,3,6 | **2,264** | **2,212** | 2,211 | 2,147 |
| | **20,996** | **27,072** | 20,181 | 25,105 |
| Non-Controlling Interests5 | **706** | **-** | 727 | - |
| Shareholders Equity | | | | |
| Share capital | | | | |
| Preferred shares | **125** | **125** | 125 | 125 |
| Common shares | **3,612** | **3,612** | 3,379 | 3,379 |
| Contributed surplus | **59** | **-** | 54 | - |
| Retained earnings | **4,566** | **4,545** | 4,400 | 4,343 |
| Additional paid in capital1 | **-** | **103** | - | 98 |
| Accumulated other comprehensive loss6 | **(816)** | **(922)** | (543) | (646) |
| Reciprocal shareholding | **(154)** | **(154)** | (154) | (154) |
| | **7,392** | **7,309** | 7,261 | 7,145 |
| Total Enbridge Inc. Liabilities and Shareholders Equity | **29,094** | **34,381** | 28,169 | 32,250 |
| Non-Controlling Interests5 | **-** | **2,459** | - | 2,885 |
| | **29,094** | **36,840** | 28,169 | 35,135 |

1. Dilution Gains

Under Canadian GAAP, dilution gains are recorded as an increase to earnings. Under U.S. GAAP, dilution gains are recorded as increases to non-controlling interest within equity. During the three and nine months ended September 30, 2010, dilutions gains of $4 million and $5 million, net of tax, respectively, were reclassified from earnings to equity. The Company did not record any dilutions gains during 2009.

2. Gain on Acquisition

Under Canadian GAAP, the original equity interest in a step acquisition continues to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and non-controlling interest in a step acquisition are re-measured to fair value on the date control is obtained. Under Canadian GAAP, the original equity interest and non-controlling interest are not re-measured to fair value.

The acquisition date fair value of the original equity interest in HCLP was $52 million. As a result of the re-measurement of Hardisty, a $20 million gain, net of tax, was recorded in earnings for the three and nine months ended September 30, 2010 under U.S GAAP. Additional information related to the Company s acquisition of HCLP is included in Note 3, Acquisitions.

The acquisition date fair value of the original equity interest in Olympic was $66 million. The re-measurement of the original interest in Olympic did not result in a gain or loss under U.S. GAAP; however, it did result in an increase to non-controlling interest relative to Canadian GAAP within equity of $4 million. Additional information related to the Company s acquisition of Olympic is included in Note 3, Acquisitions.

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, 2010, lower of cost or market adjustments resulted in a $6 million (2009 - $15 million) decrease to inventory, a $2 million (2009 - $6 million) decrease to the future income tax liability and a $21 million increase (2009 - $9 million decrease) to earnings. For the three months ended September 30, 2010, lower of cost or market adjustments resulted in a $2 million decrease (2009 - $10 million increase) to earnings.

4. Consolidation of a Limited Partnership

Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 27% interest in the partnership, resulting in an increase to assets of $8,052 million (December 31, 2009 - $6,974 million), an increase in liabilities of $6,307 million (December 31, 2009 - $4,816 million) and an increase in non-controlling interests of $1,745 million (December 31, 2009 - $2,158 million) at September 30, 2010 and no recognition or measurement changes to equity or earnings attributable to the Company as at and for the nine months ended September 30, 2010 and 2009.

5. Presentation of Non-Controlling Interests

Under Canadian GAAP earnings attributable to non-controlling interests are presented in earnings on the income statement and the non-controlling interest balance is presented as a liability on the balance sheet. Under U.S. GAAP, the earnings and retained earnings attributable to non-controlling interests are presented as a separate component of equity.

For the three and nine months ended September 30, 2010, $299 million of losses (2009 - $33 million of earnings) and $129 million of losses (2009 - $176 million of earnings) are attributable to non-controlling interests, respectively.

Included in OCI for the three months ended September 30, 2010 is an unrealized loss on cash flow hedges of $35 million (2009 - $28 million) and an after-tax change in OCI of $19 million (2009 - $40 million) attributable to non-controlling interests.

Included in OCI for the nine months ended September 30, 2010 is an unrealized loss on cash flow hedges of $65 million (2009 - $83 million) and an after-tax change in OCI of $24 million (2009 - $68 million) attributable to non-controlling interests.

6. Pension Funding Status

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 comprehensive income, 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 an increase in the net liability of $161 million (December 31, 2009 - $155 million) for the underfunded status of the plans, a decrease in future tax liability of $53 million (December 31, 2009 - $52 million) and an increase in accumulated other comprehensive loss of $106 million (December 31, 2009 - $103 million) at September 30, 2010.

The Company estimates that approximately $15 million related to pension and OPEB plans at September 30, 2010 will be reclassified into earnings in the next twelve months.

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 to 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, 2010, $90 million (December 31, 2009 - $98 million) of transaction costs were reclassified.