ENBRIDGE INC
Form 6-K
March 29, 2011

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

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

the Securities Exchange Act of 1934

Dated March 29, 2011

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

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

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

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

Form 20-F o 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 o 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 o 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 o 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 STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 33-77022) AND FORM F-10 (FILE NO. 333-152607 AND 33-170200) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following document is being submitted herewith:

- Annual Report for the year ended December 31, 2010.

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:	March 29, 2011	By:	/s/ Alison T. Love Alison T. Love Vice President, Corporate Secretary & Chief Compliance Officer

2010 was a year of significant

accomplishment and continued

growth, tempered by incidents

that will have a lasting impact

on our Company.

Enbridge had another very strong financial year in 2010, delivering outstanding organic growth across all of its business units and simultaneously securing new projects and assets that will extend the Company s enviable rate of growth well into the future.

As great as these accomplishments were, 2010 was also humbling for Enbridge as we experienced two significant crude oil pipeline leaks in the United States. Applying the lessons learned from those leaks is the top priority for the Company.

STRONG GROWTH

Enbridge again achieved industry-leading earnings per share growth in 2010. Adjusted earnings per share rose 13% to $2.66 per common share, which builds on a 25% increase in 2009.

Our 2010 growth was driven by two factors: the strong financial performance of all our businesses and the commencement of operations of $6.5 billion in new projects.

Over the past three years we have brought over $12 billion in projects into service and we currently have another $6 billion of commercially secured projects coming into service by 2014, as well as $30 billion of new opportunities under development across all of our businesses. In 2010 alone, we secured $4 billion in new growth projects and assets, and in the first two months of 2011 we announced an additional $0.4 billion in investments.

We are well positioned to meet our long-term growth objectives. We anticipate Enbridge s adjusted earnings per share will grow at an average annual rate of 10% through the middle of this decade and, with the Company s cash flow anticipated to grow at an even more rapid pace, we expect to continue delivering exceptional dividend growth to our investors. The Board has increased the 2011 dividend by 15%. Enbridge has increased its dividend an average of 11% per year over the past 10 years, and in more than 55 years as a publicly traded company we have never reduced the dividend. Few North American companies can match this record of accomplishment.

Our growth opportunities are aligned with our very reliable, low-risk business model that results in highly predictable earnings. We are involved in strategically important geographies, including the Canadian oil sands, the Bakken Formation, the Midwest Texas and Louisiana shale gas plays and offshore natural gas and oil. Our interests in wind, solar and alternative green energy power generation

are focused on the growing renewable energy demand in North America.

LIQUIDS PIPELINES

In 2010, we put into service on budget and ahead of schedule the $3.5 billion Alberta Clipper Project, which represents the largest mainline expansion in Enbridge s history, and the unique $2.3 billion Southern Lights pipeline from Chicago to Edmonton that is the first to deliver diluent to western Canada.

In the Athabasca region we have secured six new projects that are valued at $2.6 billion and are expected to go into service between 2011 and 2014. These include the expansion of the Company s Athabasca Pipelines, expansion of our Waupisoo Pipeline, three new pipelines Woodland, Wood Buffalo, and Norealis and expansion of Enbridge s Edmonton terminal facilities. Enbridge s Regional

FINANCIAL HIGHLIGHTS

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars, except per share amounts)			
Earnings per Common Share	**2.60**	4.27	3.67
[redacted]	**2.66**	[redacted]	[redacted]
[redacted]	**1.70**	[redacted]	[redacted]
[redacted]	**648**	[redacted]	[redacted]
[redacted]	**12.9%**	[redacted]	[redacted]
[redacted]	**66.7%**	[redacted]	[redacted]

OPERATING HIGHLIGHTS

[redacted]	[redacted]	[redacted]
[redacted]	2,168	[redacted]
[redacted]	291	[redacted]
[redacted]	144	[redacted]
[redacted]	276	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	1,600	[redacted]
[redacted]	1,456	[redacted]
[redacted]	1,962	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	393	[redacted]
[redacted]	1,981	[redacted]

1 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.

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

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

Oil Sands System, which currently connects five producing oil sands projects, will connect eight producing projects by 2014. We continue to hear encouraging announcements of growth and investment in the oil sands, and Enbridge is very well positioned to provide a wide range of flexible and cost effective transportation solutions to existing and new shippers.

Also in 2010, Enbridge Income Fund and Enbridge Energy Partners, L.P. completed expansions of their Saskatchewan and North Dakota systems, respectively. Additionally, they announced a new $560 million Bakken Expansion Program that will increase capacity out of the region by another 145,000 barrels per day starting in early 2013.

In May 2010, we reached a major milestone when we filed our regulatory application with the National Energy Board for the $5.5 billion Enbridge Northern Gateway Pipeline Project, a proposed twin pipeline system running between Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia to export crude oil and import condensate. We have strong commercial support for Northern Gateway, with a consortium of Canadian producers and Southeast Asian refiners acting as our funding partners as we move through the regulatory process. We are also offering Aboriginal communities along the pipeline route

up to 10% of the equity in the project. The project will bring long-term economic and social benefits to not only northern British Columbia and Alberta, but also all of Canada.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

All three of our geographically distinct gas pipeline businesses gathering and processing, offshore pipelines and long-haul transmission hold strong competitive positions.

In 2010, Enbridge Energy Partners grew its natural gas infrastructure in the Lower 48, acquiring US$700 million in assets in the prolific Granite Wash area located in the Texas Panhandle region and southwest Oklahoma.

The sanctioning by Chevron in October of its Jack St. Malo project in the Gulf of Mexico has enabled us to advance our US$400 million Walker Ridge Gas Gathering System. We are also in the engineering phase for the US$250 million Big Foot Oil Pipeline. Both of these ultra deepwater projects are commercially secured and are structured to strengthen returns and to align closely with Enbridge s reliable business model.

In early 2011, we announced a $150 million expansion of the condensate processing capacity of our Venice, Louisiana facility to accommodate additional offshore natural gas production.

We expect the expansion, which will double capacity to approximately 12,000 barrels of condensate per day, will be in service in late 2013.

The Alliance Pipeline is strategically positioned to continue to realize strong returns by virtue of its proximity to liquids-rich shale gas plays in northeast British Columbia and the Bakken Formation.

GAS DISTRIBUTION

Enbridge Gas Distribution (EGD), one of the fastest growing utilities in North America, is continuing to boost its return on investment under Incentive Regulation in Ontario. EGD is adding over 30,000 new customers a year.

In February 2011, Enbridge announced it will invest $145 million to acquire an additional 6.8% interest in Noverco, bringing its total interest to 38.9%. Noverco owns 71% of Gaz Metro Limited Partnership, which owns gas distribution and gas pipelines assets in Quebec and gas and electric power distribution and transmission assets in Vermont.

GREEN ENERGY

In 2010, we commissioned the 80-MW Sarnia Solar facility, one of the largest photovoltaic solar facilities in the world, announced the 99-MW Greenwich Wind Energy Project in Ontario and entered the U.S. green energy market by securing the 250-MW Cedar Point Wind Energy Project in Colorado.

Executive Management Team *(left to right)*

David T. Robottom *Executive Vice President & Chief Legal Officer*

Janet Holder *President, Enbridge Gas Distribution*

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

Al Monaco *President, Gas Pipelines, Green Energy & International*

Stephen J. Wuori *President, Liquids Pipelines*

Patrick D. Daniel *President & Chief Executive Officer*

We concluded 2010 with the substantial completion of the Talbot Wind Energy project in Ontario, and in February 2011 announced the acquisition of the Amherstburg and Tilbury solar projects.

Enbridge has secured over $1.5 billion in green energy projects over the past 18 months and we expect that rate of growth to continue. Our investments generate predictable and reliable returns supported by long-term power-purchase agreements with creditworthy counterparties, combined with fixed price contracts for engineering, procurement and construction. They also support our Neutral Footprint initiative to help ensure that the construction of Enbridge s new projects have no net environmental impact.

RESPONDING TO INCIDENTS

On July 26, 2010 a leak of an estimated 20,000 barrels of crude oil occurred on our Line 6B pipeline near Marshall, Michigan. That leak was the most serious environmental incident in our long history. And on September 9, 2010, an estimated 9,000 barrels of crude oil (of which approximately 1,400 barrels were removed from the pipeline as part of the repair) were released from our Line 6A in an industrial section of Romeoville, Illinois.

These incidents tested our ability to respond to the individuals and communities affected by the leaks, to the regulators and numerous agencies involved in the response effort, and to our customers whose deliveries were disrupted by the prolonged shutdown of the affected pipelines.

No accident or spill will ever be acceptable to us and we are more determined than ever to meet our goal of zero incidents. We take pride in Enbridge s employees and the commitment they have demonstrated to responding to these incidents and applying what we have learned to ensure that incidents like these never happen again. The safety and integrity of our operations remains our highest priority. Enbridge s job is to deliver the energy that North Americans need safely, reliably and efficiently. That is our primary social responsibility.

MANAGEMENT AND BOARD CHANGES

We wish to express our sincerest thanks to Steve Letwin, who retired from Enbridge as Executive Vice President, Gas Transportation & International, in October 2010. Steve was a significant contributor over his 11 years as a member of Enbridge s leadership team. Enbridge announced a new structure for its executive management team to capitalize on their strengths and reflect the continued growth and evolution of the Company.

In November 2010, the Board of Directors announced the appointment of Maureen Kempston-Darkes, retired Group Vice President and President, Latin America, Africa and Middle East, General Motors Corporation, and the first woman to lead General Motors of Canada. As a successful and accomplished Canadian businesswoman with experience in the automotive, transportation and energy industries, she brings a valued perspective to Enbridge s Board.

IN CONCLUSION

Our positive financial results in 2010 reflect the collective efforts of our 6,400 employees across the organization to achieve our vision of being the leading energy delivery company in North America. We thank all of them for their outstanding work and continuing commitment to our corporate values.

Enbridge has an exceptionally strong asset base, a proven ability to develop new businesses, and a track record of on-time, on-budget execution. The Company offers investors visible and sustained earnings growth, a substantial and growing dividend and a very reliable business model.

The unique combination of these attributes will continue to deliver superior results for our shareholders solid returns that you can count on.

David A. Arledge

Chair of the Board of Directors

Patrick D. Daniel

President and Chief Executive Officer

March 2, 2011

Board of Directors *(left to right)*

David A. Leslie *Corporate Director, Toronto, Ontario*

Charles W. Fisher *Corporate Director, Calgary, Alberta*

Patrick D. Daniel *President & Chief Executive Officer, Enbridge Inc., Calgary, Alberta*

Charles E. Shultz *Chair & Chief Executive Officer, Dauntless Energy Inc., Calgary, Alberta*

Catherine L. Williams *Corporate Director, Calgary, Alberta*

George K. Petty *Corporate Director, San Luis Obispo, California*

David A. Arledge *Chair of the Board, Enbridge Inc., Naples, Florida*

J. Lorne Braithwaite *Corporate Director, Thornhill, Ontario*

V. Maureen Kempston-Darkes *Corporate Director, Weston, Florida*

Dan C. Tutcher *Corporate Director, Houston, Texas*

J. Herb England *Chairman & Chief Executive Officer, Stahlman-England Irrigation Inc., Naples, Florida*	**James J. Blanchard** *Senior Partner, DLA Piper U.S., LLP, Beverly Hills, Michigan*

At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves

and provides guidance with respect to the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews its results. The Board also oversees identification of the Company s principal risks on an annual basis, monitors risk management programs, reviews succession planning and seeks assurance that internal control systems and management information systems are in place and operating effectively.

FINANCIAL RESULTS

Management s Discussion and Analysis

Consolidated Financial Statements

Notes to the Consolidated Financial Statements

170 Enbridge Businesses

MANAGEMENT S DISCUSSION AND ANALYSIS

This Management s Discussion and Analysis (MD&A) dated February 18, 2011 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2010, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

Overview

Enbridge is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world s longest crude oil and liquids transportation system. The Company also has a significant involvement in the natural gas transmission and midstream businesses. As a distributor of energy, Enbridge owns and operates Canada s largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a clean energy generator, Enbridge is expanding its interests in renewable and green energy technologies, including wind, solar, and geothermal energy, and hybrid fuel cells. Enbridge employs approximately 6,400 people, primarily in Canada and the United States.

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

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States, including the Enbridge System, the Enbridge Regional Oil Sands System, Southern Lights Pipeline and other feeder pipelines.

GAS DISTRIBUTION

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, processing and green energy projects, the Company s commodity marketing businesses, and international activities.

Investments in natural gas pipelines include the Company s interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in processing includes the Company s interest in Aux Sable, a natural gas fractionation and extraction business. The commodity marketing businesses manage the Company s volume commitments on Alliance and Vector Pipelines, as well as perform commodity storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company s 25.5% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge s 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, L.P. (EELP) and an overall 72% economic interest in Enbridge Income Fund (EIF), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (EIFH). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of EIF include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and partial interests in several green energy investments.

CORPORATE

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

Performance Overview

	Three Months Ended December 31,		Year Ended December 31,		
(millions of Canadian dollars, except per share amounts)	**2010**	2009	**2010**	2009	2008
Earnings Applicable to Common Shareholders					
[redacted]	**117**	[redacted]	**512**	[redacted]	[redacted]
[redacted]	**60**	[redacted]	**155**	[redacted]	[redacted]
[redacted]	**32**	[redacted]	**121**	[redacted]	[redacted]
[redacted]	**56**	[redacted]	**137**	[redacted]	[redacted]
[redacted]	**61**	[redacted]	**38**	[redacted]	[redacted]
[redacted]	**326**	[redacted]	**963**	[redacted]	[redacted]
[redacted]	**0.87**	[redacted]	**2.60**	[redacted]	[redacted]
[redacted]	**0.86**	[redacted]	**2.57**	[redacted]	[redacted]
Adjusted Earnings 1					
[redacted]	**117**	[redacted]	**512**	[redacted]	[redacted]
[redacted]	**54**	[redacted]	**167**	[redacted]	[redacted]
[redacted]	**31**	[redacted]	**123**	[redacted]	[redacted]
[redacted]	**48**	[redacted]	**209**	[redacted]	[redacted]
[redacted]	**(12)**	[redacted]	**(27)**	[redacted]	[redacted]
[redacted]	**238**	[redacted]	**984**	[redacted]	[redacted]
[redacted]	**0.64**	[redacted]	**2.66**	[redacted]	[redacted]
Cash Flow Data					
[redacted]	**375**	[redacted]	**1,851**	[redacted]	[redacted]
[redacted]	**(746)**	[redacted]	**(2,674)**	[redacted]	[redacted]
[redacted]	**152**	[redacted]	**749**	[redacted]	[redacted]

Dividends		
	163	648
	0.425	1.70
Revenues		
	3,280	11,990
	863	3,137
	4,143	15,127
Total Assets	30,120	30,120
Total Long-Term Liabilities	18,542	18,542

EARNINGS APPLICABLE TO COMMON SHAREHOLDERS

Earnings applicable to common shareholders for the three months ended December 31, 2010 were $326 million, an increase of $26 million compared with $300 million for the fourth quarter of 2009. The increase was primarily attributable to higher Sponsored Investments earnings, including Alberta Clipper contributions and a dilution gain on reduced ownership in EEP, as well as increased unrealized foreign exchange and derivative gains in Corporate. Offsetting these increases were lower contributions from Liquids Pipelines due in part to the elimination of annual performance metrics under the 2010 interim toll agreement, lower contributions from Gas Distribution due to higher operating costs and additional remediation costs on the Line 6B and 6A crude oil releases as discussed below.

Earnings applicable to common shareholders were $963 million, or $2.60 per common share, for the year ended December 31, 2010, compared with $1,555 million, or $4.27 per common share, for the year ended December 31, 2009. The Company s earnings for 2010 included the positive impacts of projects coming into service in 2010, including the Alberta Clipper, Southern Lights Pipeline and the Sarnia Solar energy projects. Compared with 2009, earnings have increased further due to customer growth in Gas Distribution and improved contributions from green energy, partially offset by less favourable weather conditions in the Company s gas distribution franchise areas. These operational improvements were overwhelmed by the absence of one-time favourable items experienced in 2009, including a $329 million gain on the disposal of Oleoducto Central S.A. (OCENSA) and unrealized derivative and intercompany foreign exchange gains.

Additionally, 2010 results were impacted by the Line 6B and 6A crude oil releases. Earnings for the fourth quarter of 2010 and for the year ended December 31, 2010 reflected the Company s share of EEP s costs, before insurance recoveries and excluding fines and penalties, of $21 million and $103 million, respectively, related to these incidents. Lost revenue associated with downtime on both Line 6B and 6A of $3 million (net to Enbridge) further contributed to the year-over-year decrease in earnings. See *Sponsored Investments Enbridge Energy Partners EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

Comparability of earnings applicable to common shareholders for the year ended December 31, 2010 with the prior year is impacted by the effect of unrealized derivative and intercompany foreign exchange gains and losses which totaled a gain of $59 million in 2010 compared with a gain of $305 million in 2009. Further, earnings for the year ended December 31, 2009 reflected gains on the disposition of investments, including OCENSA, of $354 million whereas no dispositions occurred in 2010.

Compared with 2008, earnings applicable to common shareholders for the year ended December 31, 2009 increased $234 million. Included in earnings for the year ended December 31, 2009 was a $329 million gain related to the sale of the Company s investment in OCENSA and a $25 million gain related to the sale of NetThruPut (NTP). Earnings for the year ended December 31, 2008 included a gain of $556 million related to the sale of the Company s investment in Compañía Logística de Hidrocarburos CLH, S.A. (CLH). The remaining variances primarily resulted from allowance for equity funds used during construction (AEDC) in Liquids Pipelines and Sponsored Investments, as well as a higher contribution from EEP, and movements in unrealized fair value gains and losses on derivative instruments and unrealized foreign exchange gains on the translation of foreign denominated intercompany loans.

ADJUSTED EARNINGS

Adjusted earnings were $238 million, or $0.64 per common share, for the three months ended December 31, 2010, compared with $239 million, or $0.64 per common share, for the three months ended December 31, 2009. Positive contributors in the quarter included Gas Pipelines, Processing and Energy Services whose Aux Sable and Energy Services businesses benefited from favourable margins in the period and who also incurred lower business development costs compared with the fourth quarter of 2009. Adjusted earnings from Sponsored Investments increased due to contributions from Alberta Clipper, both through EEP and EELP, and the acquisition of gas gathering assets in the fourth quarter of 2010. Partially offsetting these items are lower adjusted earnings from Liquids Pipelines due primarily to the 2010 interim toll agreement no longer including annual performance metrics, higher business development costs and higher taxes. Gas Distribution also incurred higher operating costs, depreciation and taxes in the fourth quarter of 2010 compared with the same period of 2009.

Adjusted earnings were $984 million, or $2.66 per common share, for the year ended December 31, 2010, compared with $855 million, or $2.35 per common share, for the year ended December 31, 2009. The increase in adjusted earnings primarily reflected contributions from projects coming into service, including the Alberta Clipper Project, the Southern Lights Pipeline and the Sarnia Solar Project, as well as strong performance from the Company s existing liquids and natural gas assets. The Company also realized improved adjusted earnings from Gas Distribution due to customer growth and favourable operating performance. Sponsored Investments further contributed to year-over-year increases in adjusted earnings, benefiting from EEP contributions and its expansions and acquisition completed in 2010.

Adjusted earnings for the year ended December 31, 2009 were $855 million, or $2.35 per common share, compared with $677 million, or $1.88 per common share, for the year ended December 31, 2008. The $178 million increase over 2008 was largely driven by higher adjusted earnings from Enbridge System and Southern Lights Pipeline, within Liquids Pipelines, including the impact of AEDC. Adjusted earnings in 2009 also include an increased contribution from EEP resulting from higher crude oil delivery volumes, tariff surcharges for recent expansions, and the Company s increased ownership interest. Further positive contributions were realized by Enbridge Offshore Pipelines (Offshore) due to higher volumes and Energy Services due to higher volumes and the impact of realizing favourable storage and transportation margins.

CASH FLOWS

The Company s strong operating results and the success of its growth projects resulted in cash provided by operating activities of $1,851 million for the year ended December 31, 2010. Operating cash flow, together with cash provided by financing activities, funded the Company s ongoing growth initiatives in 2010, including capital expenditures of $2,357 million.

For the three months ended December 31, 2010, cash provided by operating and financing activities substantially funded investing activities of $746 million, which consisted primarily of capital expenditures. The decline in additions to property, plant and equipment in the fourth quarter of 2010 compared with the fourth quarter of 2009 reflected the completion of several substantial construction projects that were under development in 2009, including Alberta Clipper and Southern Lights Pipeline.

DIVIDENDS

The Company has paid, and consistently increased, common share dividends since its public inception in 1953. Based on estimated 2011 dividends, the annual rate of increase has averaged 10.8% since 2001 and 10.1% since inception. In December 2010, the Company announced a 15% increase in its quarterly dividend to $0.49 per common share, or $1.96 annualized, effective March 1, 2011. The Company continues to target a payout of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2011 payout is expected to be near the upper end of the range. In 2010, dividends paid per share were 64% of adjusted earnings per share (2009 63%, 2008 70%).

The following chart shows dividends per common share for the last 10 years, as well as estimated dividends for 2011, based on the quarterly dividend of $0.49 per common share declared by the Board of Directors on December 1, 2010.

REVENUES

The Company generates revenue from two primary sources: commodity sales, and transportation and other services.

Commodity sales revenue of $11,990 million (2009 $9,720 million) is earned through the Company s natural gas distribution and energy marketing activities and is subject to fluctuations in commodity prices. While revenues generated by the natural gas distribution business vary with the price of natural gas, earnings are not affected due to the pass through nature of these costs. Similarly, the impact of commodity prices on revenues derived from the Company s energy marketing activities do not directly impact earnings since commodity prices also affect input costs associated with such activities. The period-over-period variances in commodity sales are primarily driven by natural gas and crude oil commodity prices and similar trends were experienced in commodity costs over these periods.

Transportation and other services includes revenue derived from the Company s liquids transportation and natural gas transmission services, renewable energy generation and related services. Contributing to the increase in transportation and other services revenue in 2010 are Alberta Clipper and Southern Lights Pipeline, which entered service in April 2010 and July 2010, respectively.

For the year ended December 31, 2010, transportation and other services revenue increased to $3,137 million compared with $2,746 million in 2009. Main contributors to this variance include increased contributions from Liquids Pipelines growth projects that entered service in 2010, including Alberta Clipper and Southern Lights Pipeline and full year contributions from the initial phase of the Sarnia Solar Project which entered service in December 2009 as well as the expansion which was completed in September 2010.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge s and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , believ and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; 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 underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company s services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company s services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

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

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss 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* for a reconciliation of the GAAP and non-GAAP measures.

Corporate Vision and Key Objective

Enbridge s vision is to be the leading energy delivery company in North America. While the Company may be viewed as having achieved elements of this vision, enhancing and sustaining this position remains a continuing long-term pursuit. The Company s objective is to generate superior economic value for shareholders through investing capital in energy infrastructure businesses which generate reliable earnings and cash flow. Consistently applied, such stewardship should continue to generate attractive returns on invested capital and, in turn, provide for consistent and growing dividend distributions and related capital appreciation to its shareholders.

Corporate Strategy

In support of its long-term vision and objective, the Company employs several key strategies that guide decision making across the enterprise. The Company s strategies include:

- focusing on project execution and operating excellence;
- leveraging the strategic location of its existing asset base;
- developing new platforms for growth and diversification;
- maintaining financial strength and flexibility; and
- developing people, safety and environmental stewardship, and corporate social responsibility.

Enbridge s strategy is reviewed annually with direction from its Board of Directors. The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial criteria before being pursued.

FOCUSING ON PROJECT EXECUTION AND OPERATIONS

Effective management of operations and project execution is the foundation of Enbridge s strategic plan. Operational excellence is particularly critical in an environment where customers have become increasingly cost conscious, competition in the Company s core business has intensified and environmental stewardship has heightened.

Successful execution of the existing slate of commercially secured projects is a significant driver of Enbridge s near-term earnings and cash flow growth, and, therefore, a strategic priority. Project execution is a core competency at Enbridge and the Company continues to build upon its project management skills and processes, primarily through the Major Projects support team which was established in early 2008. Major Projects manages projects above $50 million for all liquids, natural gas and renewable projects and continues to deliver projects on time and on budget. Major Projects focuses on success factors such as cost estimation, regulatory permitting, material and labour sourcing and project governance. All Major Projects are governed through a formal, disciplined stage gating process which requires the completion of pre-defined project deliverables, such as project execution and risk management plans, prior to management approving projects to proceed through predefined stage gates within the project lifecycle. This competency is highly valued and represents another Enbridge strength when competing for new business.

With respect to safety and system integrity, Enbridge employs the best available practices and technologies for integrity management, systems maintenance and operations in order to mitigate risks to the public, our employees and the environment.

STRENGTHENING OUR CORE BUSINESS

The Company has an established history of serving the North American transportation needs of key crude oil and natural gas markets. The Company is focused on adding value for customers and improving customers profitability. This focus has aligned the Company with its customers and relevant supply and demand fundamentals and has consistently formed a basis for the Company s strategy. However, evolving supply and demand fundamentals and growing competition are serving to create new opportunities and challenges within the Company s core businesses. Amid this changing business environment, the Company is strengthening its core business position and aggressively pursuing new opportunities to expand and extend its current asset base.

Extending the reach of the current asset base is a multi-faceted objective. Key strategies within the Liquids Pipelines segment include regional pipeline development, gathering system and storage infrastructure expansion and new market access. Regional pipeline development primarily includes projects which connect new oil sands lease production to existing hubs upstream of the Canadian mainline. Enbridge s planned investment of $2.6 billion in commercially secured regional oil sands transportation facilities that are expected to go into service between 2011 and 2014 continue to advance this objective. The Company is also expanding its gathering systems in Saskatchewan and North Dakota which are strategically located to capture increased production from the Bakken play. As transportation needs grow so too do terminal and storage infrastructure requirements throughout the network, and the Company s strategy is to seek opportunities to provide additional capacity in the Fort McMurray and Hardisty, Alberta regions as well as in the Cushing, Oklahoma area. The Company continues to pursue opportunities to provide its customers broader market access for Canadian bitumen and synthetic crudes and provide new sources of supply for refiners. These efforts include leveraging existing pipeline networks into additional United States markets as well as developing the proposed Northern Gateway pipeline to provide access to markets off the Pacific Coast of Canada.

The fundamentals of the natural gas market in North America have been altered significantly in recent years with the emergence of unconventional shale gas plays. The Company s natural gas strategy includes expanding its footprint in these emerging areas. Alliance Pipeline is well positioned to service the Montney play in northeast British Columbia and the Bakken play, and is currently evaluating opportunities to expand its service offerings in that area. In addition to these onshore strategies, the Company continues to pursue and win natural gas gathering expansion opportunities for ultra-deep projects in the Gulf of Mexico which improve the risk and return profile of its investment in this area.

DEVELOPING NEW PLATFORMS FOR GROWTH AND DIVERSIFICATION

The development of new platforms to diversify and sustain long-term growth is an important strategy for Enbridge. Renewable energy is a significant source of potential new growth as government initiatives and changing social beliefs are creating new opportunities to deliver green energy solutions with risk and return characteristics consistent with Enbridge s business model. Renewable energy projects can deliver stable cash flows and attractive returns through the use of long-term power purchase agreements and fixed price engineering, procurement and construction contracts. Renewable energy is also an important part of Enbridge s corporate social responsibility strategies, particularly with respect to greenhouse gas emissions (GHG) and the environment. Business development efforts in renewable energy are focused primarily on clean power projects, including wind, solar, waste heat recovery, fuel cell, geothermal and natural gas fired generation initiatives.

Similar to renewable energy, carbon dioxide (CO2) capture and sequestration not only supports Enbridge s social investment strategy but also represents a potentially significant investment opportunity, should the technology prove viable.

The Company s Alternative and Emerging Technologies group is exploring other longer-term energy technologies to sustain the Company s favourable position. In addition, the International group is actively seeking new opportunities outside of North America.

PRESERVING FINANCIAL STRENGTH AND FLEXIBILITY

Disciplined capital management is a fundamental and company differentiating characteristic. As an asset-intensive business, Enbridge creates value for its investors through maximizing the spread between its return on invested capital and its cost of funds. Enbridge s financial strategies are designed to ensure the Company has sufficient liquidity to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain and improve Enbridge s credit ratings, diversify its funding sources and maintain ready access to capital markets in both Canada and the United States.

A key tenet of the Company s reliable business model is mitigation of exposure to market price risks. As a result, the Company has developed a robust risk management process which ensures earnings volatility from market price risk remains contained. Enbridge will continue to proactively hedge interest rate, foreign exchange and commodity price exposures. As well, the continued management of counterparty credit risk remains an ongoing priority.

DEVELOPING PEOPLE

Strong employees and leaders are the foundation of any successful company and developing its people remains a strategic priority for Enbridge. Key priorities related to building and improving Enbridge s organizational and workforce capabilities and Human Resource services include:

- strengthening the leadership culture;
- enabling and accelerating career development for leaders and employees;
- developing capability and capacity for effective change management;
- reinforcing a values-based organization; and
- ensuring human resource systems can provide strategic information for decision making.

RESPONDING TO ENVIRONMENTAL PRIORITIES

Enbridge has strong corporate social responsibility practices. Enbridge defines corporate social responsibility as conducting business in an ethical and responsible way, protecting the environment and the health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures with which the Company works. Enbridge s 2010 Corporate Social Responsibility Report can be found at http://www.enbridge.com/AboutEnbridge/CorporateSocialResponsibility/CSRReports.aspx. None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.

In 2009, the Company launched an enterprise-wide goal of achieving a neutral environmental footprint by 2015. The goal consists of three key commitments:

- we will plant a tree for every tree we remove to build new facilities;
- we will conserve an acre of natural or wilderness land for every acre we permanently impact from the construction of new facilities; and
- we will generate a kilowatt hour of renewable energy, through our investments in renewable energy, for each kilowatt hour of power consumed by our operations.

Land impacts will be addressed as soon as practically possible, but within five years of the in-service date of the project responsible for triggering the neutral footprint obligation. To achieve its neutral footprint goal, Enbridge is working with the Nature Conservancy of Canada and will work with nature conservancies in the United States to help purchase natural wilderness lands throughout North America. Progress on the Company s neutral footprint initiative include:

- 155,000 trees removed; 150,000 tree seedlings planted
- 624 acres disturbed; 1,118 acres conserved through the Nature Conservancy of Canada

- electricity consumption is forecast to increase, over the 2008 consumption level, by 1,077 gigawatts per hour (GWh) by 2015; Enbridge s existing renewable power generating facilities and those under construction will produce approximately 2,170 GWh

Industry Fundamentals

SUPPLY AND DEMAND FOR LIQUIDS

Canadian crude exports continue to grow into the United States, further solidifying Canada as its number one supplier. Combined conventional and oil sands established reserves of approximately 175 billion barrels suggest that Canada will continue to grow this relationship, albeit against growing concern over the environmental footprint of oil sands crude. The National Energy Board (NEB) estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.6 million barrels per day (bpd) in 2010 (2009 2.4 million bpd; 2008 2.4 million bpd).

Sustained oil prices above the $70 mark have led to resurgence in oil sands project announcements that had slowed during the economic downturn. These announcements provide optimism for oil sands production growth in the medium term. The question remains whether industry can avoid the capital cost inflation which overwhelmed projects during the most recent boom as companies competed for resources. The Canadian Association of Petroleum Producers (CAPP) June 2010 growth case estimates indicate that future WCSB production is expected to steadily increase by 4% annually to more than 3.7 million bpd by 2020. This forecasted growth of 1.1 million bpd is largely attributed to increased oil sands production in Alberta.

World crude oil demand was approximately 2 million bpd higher in 2010 relative to 2009, with China as the major contributor of demand growth. North American demand growth remains relatively flat and is projected to remain that way into the near future. The continued growth of biofuels further suppresses United States crude requirements. Canadian crude imports into the United States Midwest are growing while United States overall crude imports from other countries has declined relative to past years. Midwest refinery runs and margins are showing stability versus other markets. Planned reconfiguration of refineries in the Midwest will increase the demand for Canadian crude into one of Enbridge s key markets.

With the expected increase in heavy oil production in western Canada, there is an increasing requirement for condensate (or similar light commodity) to be used as a blending agent in order to transport these high viscosity volumes to market. Condensate is a light hydrocarbon which is conventionally a bi-product of natural gas production or NGLs fractionation. Production of this commodity is decreasing in western Canada but, with the increasing demand for diluents from heavy oil producers, there has been an increasing need to import. Currently, volumes are transported via rail to Alberta from the United States as well as from international sources via tankers and rail from the West Coast. Also in mid-2010, Enbridge s Southern Lights condensate pipeline began importing incremental volumes of condensate from the United States to Alberta to meet producer s needs.

SUPPLY AND DEMAND FOR NATURAL GAS

The North American natural gas market has entered into a period of abundant supply primarily due to horizontal drilling of shale gas plays in the United States. Rapidly evolving drilling and completion technologies have increased the average productivity of new wells and reversed the established trend of diminishing productivity. Improved well productivity and drilling efficiencies have combined to reduce production costs such that shale gas production is among the most economic source of gas in North America. Considering the widespread nature and vast resource endowment of unconventional gas, North America is expected to have excess supply for some time. As such, several projects to import liquefied natural gas (LNG) into North America were cancelled during the year; instead, proposals to export LNG derived from domestic production have gained momentum. Further, projects to transport northern gas to southern markets have been deferred. Despite delays with the construction and commissioning of liquefaction facilities, global LNG capacity expanded significantly in 2010. LNG imports are expected to remain close to contractual minimums for several years; conversely, North American spot cargoes of LNG are expected to be delivered to markets in Asia, Europe and South America in the near future.

Emphasis in drilling shifted over the year from the established shale plays in the mid-continent region (such as the Barnett, Fayetteville and Woodford shale plays) to the massive and higher-productivity plays such as Haynesville in northwest Louisiana, Marcellus in Appalachia and the Montney region in northeast British Columbia. In addition, producers have been increasingly shifting attention to more liquids-rich targets; namely, the Eagle Ford shale and Granite Wash plays in Texas. The rapid increase in drilling and corresponding production growth will continue to lead to abundant opportunities for gathering, processing and short-haul connectivity.

Regional production growth patterns have also impacted long-haul infrastructure. For example, rapid growth in production from the Marcellus shale play has contributed to sharply displace imports of Canadian gas into the northeast United States and has even spurred proposals to export gas into eastern Canada.

Weather extremes in both winter and summer seasons helped to propel North American natural gas demand in 2010. Gas demand was further supported by the recovering industrial sector following the recent economic recession, and an increased amount of gas for coal substitution in power generation as gas prices were comparatively weak. Although economic recovery was slowing in the second half of 2010, growth is expected to continue at a modest pace into 2011. Overall, natural gas demand should experience moderate growth over the next several years.

As growth in unconventional gas supply continues to outpace growth in demand, North America is expected to remain in a relatively low gas price environment. Moreover, gas prices will continue to experience downward pressure until gas drilling is reduced sufficiently to temper production growth. Oil prices, in contrast, are expected to increase; consequently, the wide disparity between gas and oil prices should continue to support strong gas processing and fractionation spreads.

SUPPLY AND DEMAND FOR GREEN ENERGY

While traditional forms of energy are expected to represent the major source of North American energy supply for years to come, a grass roots shift to a lower carbon intensive economy has commenced. As overall North American energy needs continue to grow, particularly the need for electricity to meet commercial and residential demand, opportunities arise for renewable energy projects driven by reduced reliance on carbon-intensive fuels and heightened environmental awareness. Renewable energy, including wind, solar and geothermal, is attractively positioned to capture a significant portion of incremental and replacement generation capacity over the next 25 years.

Electricity demand growth is expected to average approximately 1% to 2% annually to 2035. The Energy Information Administration (EIA) forecasts that United States generation capacity will increase by 220,000 megawatts (MW) or over 20% from 2010 to 2035, with the vast majority of new generation coming from gas-fired generation and renewable energy sources. According to the NEB, average Canadian electricity demand is expected to grow by 1% per year over the next ten years. Growth in nuclear and coal-fired generation is expected to be limited due to permitting challenges, long lead times and uncertainty of environmental regulations, leaving opportunity for incremental demand to be met by renewable sources and natural gas.

Expanding renewable energy infrastructure in North America is not without challenges. Projects are typically highly capital intensive and renewable technology is in early stages relative to mature energy sources. Further, renewable projects must balance the benefit of reduced carbon emissions with land disturbances and projects aesthetics. High quality wind and solar resources may often be found in regions at long distances from high demand markets, introducing the need for new transmission capacity to move the increasing supply of renewable power to markets. Renewable generation results in greater load variability, creating further opportunities for gas-fired generating capacity to support system reliability. Natural gas is abundant and low cost and will form a growing part of the generation supply mix in North America.

Many factors will impact the pace of future development in renewable energy, including, but not limited to, the pace of economic recovery, technological advances, future energy or climate change regulations and continued government support. The forecasted increase in power generation arising from renewable sources is in part supported by government incentives. The continuing ability to obtain tax or other government incentives, and the ability to secure long-term power purchase agreements through government or investor-owned power authorities is required to support project economics based on current costs and technologies. What is clear is that a mix of alternative energy sources will play an increasingly important role in the North American energy space for years to come and there will be a continued drive to develop and promote green energy.

Growth Projects

Over the last three years Enbridge has placed into service over $12 billion in growth projects. In 2010 alone, Enbridge placed into service $6.5 billion of growth projects, including the $3.5 billion Alberta Clipper project, the largest liquids pipeline project in the Company s history, as well as the $2.3 billion Southern Lights Pipeline. Enbridge has also secured over $6 billion in new infrastructure growth projects in strategically significant areas including the Canadian Oil Sands and Bakken formation, mid-west Texas and Louisiana shale gas plays and offshore natural gas and oil, as well as wind, solar and other renewable projects. In addition, the Company has a further $30 billion in growth opportunities under development, but not yet commercially secured, for the post-2011 period, of which it expects to be successful on a significant portion.

The table below summarizes the current status of the Company s commercially secured projects, separated into the Company s business segments. These growth projects are expected to help Enbridge sustain its anticipated average annual earnings per share growth rate of 10% through the middle of this decade.

(Canadian dollars, unless stated otherwise)	Actual/Estimated Capital Cost 1	Expenditures to Date	Expected In-Service Date	Status
LIQUIDS PIPELINES				
1. Alberta Clipper Canadian portion	$2.2 billion	$2.2 billion	2010	Complete
2. Southern Lights Pipeline	$0.5 billion + US$1.6 billion	$0.5 billion + US$1.5 billion	Light Sour Line 2009; Diluent Line 2010	Complete
3. Christina Lake Lateral Project	$0.3 billion	$0.1 billion	2011	Under construction
4. Woodland Pipeline	$0.5 billion	No significant expenditures to date	2012	Entering construction phase
5. Edmonton Terminal Expansion	$0.3 billion	No significant expenditures to date	2011 2012 (in phases)	Regulatory and pre-construction
6. Wood Buffalo Pipeline	$0.4 billion	No significant expenditures to date	2013	Regulatory and pre-construction
7. Norealis Pipeline	$0.5 billion	No significant expenditures to date	2013	Regulatory and pre-construction
8. Waupisoo Pipeline Expansion	$0.4 billion	No significant expenditures to date	2013	Pre-construction
9. Athabasca Pipeline Capacity Expansion	$0.4 billion	No significant expenditures to date	2013 2014 (in phases)	Regulatory and pre-construction
10. Fort Hills Pipeline System	$2.0 billion	$0.1 billion	TBD	Commercially secured; pending customer timing
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
11. Sarnia Solar Project	$0.4 billion	$0.4 billion	2010	Complete
12. Talbot Wind Energy Project	$0.3 billion	$0.3 billion	2010	Complete
13. Greenwich Wind Energy Project	$0.3 billion	$0.2 billion	2011	Under construction
14. Cedar Point Wind Energy Project	US$0.5 billion	US$0.4 billion	2011	Under construction
15. Amherstburg/Tilbury Solar Projects	$0.1 billion	No significant expenditures to date	2011/2010	Under construction/ Complete
16. Venice Gas Processing Facility	$0.2 billion	No significant expenditures to date	2013	Pre-construction
17. Walker Ridge Gas Gathering System	US$0.4 billion	No significant expenditures to date	2014	Pre-construction
18. Big Foot Oil Pipeline	US$0.2 billion	No significant expenditures to date	2014	Pre-construction

SPONSORED INVESTMENTS

19. EEP/EELP Alberta Clipper United States portion	US$1.2 billion	US$1.2 billion	2010	Complete
20. EIF Saskatchewan System Capacity Expansion	$0.1 billion	$0.1 billion	2010	Complete
21. EEP Bakken Expansion Program	US$0.4 billion	No significant expenditures to date	2013	Regulatory and pre-construction
22. EIF Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Regulatory and pre-construction

1 These amounts are estimates only and subject to upward or downward adjustment based on various factors.

Risks related to the development and completion of growth projects are described under

Risk Management and Financial Instruments.

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 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 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 making the tariffs effective 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 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, narrow 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 cost of the project was US$1.6 billion for the United States segment and $0.5 billion for the Canadian segment. 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 hearing process has been initiated. The NEB has yet to confirm the process, if any, to be followed regarding the Canadian tariff challenge. No material financial impacts to the Company are anticipated.

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 facilities are expected to be in service in the third quarter of 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 may be extended from Cheecham to Edmonton as part of future expansions. The Woodland Pipeline is being undertaken as a joint venture between Enbridge, Imperial Oil and ExxonMobil. Regulatory approval for the Phase I facilities was received from the Energy Resources Conservation Board (ERCB) in June 2010 and construction is underway. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion. Enbridge expects the pipeline will come into service in late 2012.

Edmonton Terminal Expansion

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge s Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of a short segment of pipeline and related infrastructure. Subject to regulatory approval and construction pace, the expansion is expected to be completed in 2012.

Wood Buffalo Pipeline

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 already delivers crude oil from several oil sands projects to the Edmonton mainline hub. The new Wood Buffalo pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion and, pending 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 (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion. Subject to regulatory approval, the facilities are expected to be in service in late 2013.

Waupisoo Pipeline Expansion

The Waupisoo Pipeline Expansion, which received regulatory approval in November, 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 recent additional shipper commitments of 229,000 bpd. 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 its full capacity to accommodate additional contractual commitments including recent incremental shipping commitments by the Christina Lake Oilsands Project operated by Cenovus. This expansion will increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on crude slate. The estimated cost of this full expansion is approximately $0.4 billion with an expected in service date of 2013 for an initial 430,000 bpd of capacity with the balance of the capacity expected to be available by early 2014, subject to regulatory approval. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Fort Hills Pipeline System

In November 2007, Enbridge was selected by Fort Hills Energy L.P. (FHELP) as its pipeline and terminaling services provider for the initial phase of the Fort Hills project and all subsequent expansions. In late 2008, FHELP announced that its final investment decision for the mining portion of the project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. Accordingly, the scope of the Fort Hills Pipeline System is being reevaluated by FHELP and the planned in-service date for the project has been deferred beyond the original planned date of mid-2011. FHELP has until June 2011 to give notice to proceed. Expenditures to date are approximately $0.1 billion and are commercially recoverable from FHELP.

Northern Gateway Project

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

Northern Gateway submitted an application to the NEB on May 27, 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. The JRP conducted sessions with the public 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 decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. On January 19, 2011, the JRP advised that prior to issuing a procedural order it requires additional detail on the design and risk assessment of the pipelines. This information will be provided to the JRP along with prior commitments for other updates in the first quarter of 2011.

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 by late 2016 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html and Enbridge also maintains a Northern Gateway Project 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.northerngateway.ca. None of the information contained on, or connected to, the JRP website, the Northern Gateway Project website or Enbridge s website is incorporated in or otherwise part of this MD&A.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Sarnia Solar Project

The Company developed the 80-MW Sarnia Solar Project with First Solar, Inc. (First Solar). 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 developed the 99-MW Talbot Wind Energy Project near Chatham, Ontario with Renewable Energy Systems Canada Inc. (RES Canada). The project was completed in December 2010. Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens is providing operations and maintenance services for the wind turbines. The Talbot Wind Energy Project power output is sold to the OPA under a 20-year power purchase agreement. The final capital cost of the project was approximately $0.3 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 with RES Canada. Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada is constructing the project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens will provide 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. The project 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 $0.2 billion.

Cedar Point Wind Energy Project

Enbridge is developing the 250-MW Cedar Point Wind Energy Project, near Denver, Colorado with RES Americas, at an expected cost 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$0.4 billion.

Neal Hot Springs Geothermal Project

The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. 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 project.

Amherstburg and Tilbury Solar Projects

The Company entered into agreements to acquire two new solar energy projects totaling 20 MW generating capacity from First Solar for $0.1 billion. The 5-MW Tilbury Solar Project, completed in December 2010, is located in Tilbury, Ontario. The Amherstburg II Solar Project, located in Amherstburg, Ontario, consists of two separate projects of 10 MW and 5 MW each. First Solar constructed (and, in the case of the Amherstburg II Solar Project, will construct) the projects for Enbridge under fixed price engineering, procurement and construction contracts. Construction is expected to begin in March 2011 and is expected to be complete in the third quarter of 2011. Enbridge will sell the facilities power output to the Ontario Power Authority pursuant to 20-year power purchase agreements under the terms of the Ontario Government s Renewable Energy Standard Offer Program.

Venice Gas Processing Facility

On January 31, 2011, the Company announced plans for an estimated $0.2 billion expansion of the condensate processing capacity of its Venice, Louisiana facility within its offshore gas business. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge s onshore facility at Venice via Enbridge s Mississippi Canyon offshore pipeline where it will be processed to separate and stabilize the condensate. The expansion, which will more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

Walker Ridge Gas Gathering System

The Company executed definitive agreements in the last quarter of 2010 with Chevron Corp. to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day (bcf/d). WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion.

Big Foot Oil Pipeline

The Company entered into a letter of intent (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 plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion and is expected to be in service in 2014.

SPONSORED INVESTMENTS

Bakken Expansion Program

EEP and 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. As of August 2010, EEP and EIF had received sufficient long-term shipping commitments from anchor shippers to enable the Bakken Expansion Program to proceed. A binding open season was subsequently conducted to enable other shippers to secure capacity on the expansion at the same terms as the anchor shippers, which was successfully concluded in February 2011 with commitments received for an aggregate of 100,000 bpd of capacity. The Bakken Expansion Program is expected to be completed by the first quarter of 2013.

Enbridge Income Fund

Saskatchewan System Capacity Expansion

Phase II of the Saskatchewan System Capacity Expansion included three separate projects that served to reduce capacity constraints at a variety of locations. Collectively, the projects increased capacity across the system by approximately 125,000 bpd. Construction was substantially completed in December 2010. The final capital cost of the projects was approximately $0.1 billion.

CORPORATE

Project Pioneer

In June 2010, Enbridge announced it will participate in the development of the TransAlta-led Project Pioneer, Canada s first fully-integrated carbon capture and storage (CCS) project involving retro-fitting a coal-fired electricity plant. When complete, Project Pioneer is expected to be one of the largest CCS facilities in the world and among the first to have an integrated underground storage system. Enbridge brings to Project Pioneer expertise in the design and construction of pipeline infrastructure, as well as extensive knowledge in CO2 sequestration.

Liquids Pipelines

EARNINGS

(millions of Canadian dollars)	**2010**	2009	2008
Enbridge System	**327**	295	212
Enbridge Regional Oil Sands System	**73**	72	69
Southern Lights Pipeline	**82**	58	27
Spearhead Pipeline	**29**	17	12
Feeder Pipelines and Other	**1**	12	12
Adjusted Earnings	**512**	454	332
Enbridge Regional Oil Sands System leak remediation costs		(9)	
Feeder Pipelines and Other asset impairment loss			(4)
Earnings	**512**	445	328

Liquids Pipelines adjusted earnings were $512 million in 2010 compared with adjusted earnings of $454 million in 2009 and $332 million in 2008. The adjusted earnings increases were supported by substantially all segment assets, but were primarily due to bringing into service the new Alberta Clipper and 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 for the year ended December 31, 2010 was $29 million (2009 $74 million; 2008 $18 million). Recognition of AEDC on Alberta Clipper ceased following its in service date of April 1, 2010 when cash tolls commenced. The earnings impact of AEDC for the Southern Lights Pipeline was $32 million (2009 $44 million; 2008 $27 million) for the year ended December 31, 2010. Recognition of AEDC on the Southern Lights Pipeline ceased following its in service date of July 1, 2010.

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

- 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.
- In the fourth quarter of 2008, the Company recorded an impairment loss of $4 million on Manyberries Pipeline, a small feeder pipeline located in Canada.

ENBRIDGE SYSTEM

The mainline system is comprised of Enbridge System and Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines with a combined capacity of approximately 2.5 million bpd, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included within the Enbridge System and located in eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd. Average system utilization in 2010 was 79% and it is expected to decrease in 2011 due to a combination of additional pipeline capacity being added to the system by the Company in 2010 and a new pipeline placed into service by a competitor during the year.

Incentive Tolling

Tolls on Enbridge System are governed by various agreements, which are subject to the approval of the NEB. The NEB s jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the incentive tolling settlement (ITS) applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement, the SEP II Risk Sharing agreement, Alberta Clipper agreement and the Southern Access Expansion agreement which are recovered via the Mainline Expansion Toll. Tolls on the core mainline system have been governed by ITS since 1995, with the most recent ITS term effective through 2010. The Company has reached agreement with industry to roll forward the 2010 ITS agreement for a year and will file the 2011 ITS with the NEB in March 2011. The 2011 ITS has similar terms as the 2010 ITS. Discussions with industry continue for a longer term settlement agreement which will support a competitive toll structure. Until all matters before the NEB are settled, interim tolls will continue to be collected for the Enbridge System.

The ITS agreement allows for continued throughput protection on the Canadian mainline, the flow through of costs not controllable by Enbridge and includes an earnings incentive mechanism for controllable costs. The NEB Line 9 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 including the long-term Canadian mainline tolling agreement.

In conjunction with the Terrace Agreement, the 2010 ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company was largely insulated from volume fluctuations beyond its control. Accordingly the agreements establish tolls based on an agreed capacity and an allowed revenue requirement. Where actual volumes on the pipeline fall short of the agreed capacity and Enbridge is unable to fully collect its annual revenue requirement, the deficiency is collectible from shippers in the following year and a receivable, referred to as tolling deferrals, is recognized.

This basis may affect the timing of recognition of revenues compared with that otherwise expected under Canadian GAAP for companies that are not rate-regulated. As at December 31, 2010, $91 million (2009 $98 million) was recorded as tolling deferrals.

Enbridge pays taxes each year only on the tolls collected in cash; therefore the tax payable on the tolling deferrals lags behind the recognition of the revenue. As the Terrace capacity is increasingly utilized, there will be less tolling deferrals recorded and more cash tolls collected. This will result in the Company paying taxes in future years on both the tolling deferral realization and the current year s cash tolls.

Results of Operations

Enbridge System earnings were $327 million for the year ended December 31, 2010 compared with $295 million for the year ended December 31, 2009. The increase in earnings resulted from a higher Alberta Clipper contribution since entering service on April 1, 2010 and favourable operating performance. These positive factors were partially offset by higher taxes in the Terrace component.

Enbridge System earnings were $295 million for the year ended December 31, 2009 compared with $212 million for the year ended December 31, 2008. Enbridge System earnings increased due to increased tolls from a higher rate base as a result of Line 4 entering service in April 2009, lower financing costs as well as higher AEDC on Alberta Clipper. These positive impacts were partially offset by higher operating costs, including compensation.

ENBRIDGE REGIONAL OIL SANDS SYSTEM

Enbridge Regional Oil Sands System includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as a variety of other facilities including the MacKay River, Christina Lake, Surmont and Long Lake facilities. It also includes Hardisty Caverns Limited Partnership, which provides storage service; and three large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta, the Cheecham Terminal, located 95 kilometres south of Fort McMurray where the Waupisoo Pipeline initiates, and the Hardisty Contract Terminal, one of the largest crude oil terminals in North America.

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, that links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline has an ultimate design capacity of approximately 570,000 bpd, dependent on viscosity of crude being shipped. It is currently configured to transport approximately 345,000 bpd.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered into service on May 31, 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge s Cheecham Terminal and terminates at its Edmonton Mainline Terminal.

The pipeline currently has a design capacity, dependent on crude slate, of up to 350,000 bpd, which can ultimately be expanded to 600,000 bpd.

Enbridge has a long-term (25-year) take-or-pay commitment with the four founding shippers on the Waupisoo Pipeline who collectively have contracted for approximately one-third of the initial capacity on the line. The associated revenues provide for a base return on equity (ROE) with significant upside potential as incremental founders and third party volumes are added.

The Hardisty Contract Terminal, which is comprised of 19 tanks with a working capacity of approximately 7.5 million barrels of storage, was fully operational by October 1, 2009. In June 2010, the Company acquired the remaining 50% of the Hardisty Caverns Limited Partnership (Hardisty Caverns) previously owned by CCS Corporation for $52 million. The Hardisty Caverns facility, now wholly owned by Enbridge, also includes four salt caverns totaling 3.1 million barrels of capacity. The capacity at the facility is fully subscribed under long-term contracts that are generating revenues from storage and terminalling fees.

Results of Operations

Adjusted earnings for the year ended December 31, 2010 were $73 million compared with $72 million for the year ended December 31, 2009 and $69 million for the year ended December 31, 2008. In both the year ended December 31, 2010 and December 31, 2009, the increase in Enbridge Regional Oil Sands System adjusted earnings reflected higher volumes, increased tolls on certain laterals and the continued positive impact of terminal infrastructure additions, partially offset by higher operating costs.

Enbridge Regional Oil Sands System earnings for 2009 were impacted by a $9 million after-tax expense resulting from the clean up and remediation costs related to a valve leak within the Enbridge Cheecham Terminal in January 2009, which is not indicative of the expected future performance of this asset.

SOUTHERN LIGHTS PIPELINE

The 180,000 bpd, 20-inch diameter Southern Lights Pipeline was placed into service on July 1, 2010 and began transporting diluent from Chicago, Illinois to Edmonton, Alberta.

Enbridge receives tariffs under long-term (15-year) contracts with committed shippers. Tariffs provide for recovery of all operating and debt fiancing costs plus a ROE at a pre-determined rate. Uncommitted volumes, up to a specified amount, provide for tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers.

Results of Operations

Earnings for the year ended December 31, 2010 were $82 million compared with $58 million for the year ended December 31, 2009. 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. The increase in 2010 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.

Earnings for the year ended December 31, 2009 were $58 million compared with $27 million for the year ended December 31, 2008. The increased earnings reflected AEDC recognized on a growing capital base while the project was under construction. In 2009, earnings from the new light sour pipeline, which became operational during the first quarter of 2009, were also reflected in earnings.

SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from Chicago, Illinois to Cushing, Oklahoma. The performance of this pipeline steadily increased and with further support of new committed shippers, the Spearhead Pipeline Expansion was completed in May 2009. This expansion increased the capacity from 125,000 bpd to 193,300 bpd from the new initiating point of Flanagan, Illinois to Cushing.

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

Results of Operations

Spearhead Pipeline earnings increased to $29 million for the year ended December 31, 2010 compared with $17 million for the year ended December 31, 2009 and $12 million for the year ended December 31, 2008. The earnings increases were due to higher volumes resulting from the expansion completed in May 2009. Earnings during 2010 were also positively impacted by the recognition of make-up rights which expired in the period, and lower operating costs.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company s 85% interest in Olympic Pipeline Company (Olympic Pipeline), the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel, and jet fuel. It also includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta; interests in a number of liquids pipelines in the United States; contract tankage facilities; and business development costs related to Liquids Pipelines activities.

Results of Operations

Adjusted earnings for Feeder Pipelines and Other were $1 million in 2010 compared with $12 million in both 2009 and 2008. The adjusted earnings decrease for 2010 compared with 2009 was due to a number of small factors including a decrease in earnings from Toledo Pipeline due to the Line 6B shutdown, a decrease in earnings from Olympic Pipeline, as well as an increase in business development costs.

BUSINESS RISKS

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

Supply and Demand

The expansion of the Company s liquids pipelines depends on the supply of, and demand for, crude oil and other liquid hydrocarbons from western Canada. Supply, in turn, depends on a number of variables, including the price of crude oil and bitumen, the availability and cost of capital and labour for oil sands projects, the price of natural gas used for steam production and changes in plans by shippers. Supply risk to existing facilities is largely mitigated given the Company s throughput insensitive commercial terms or cost of service arrangements on many of its Liquids Pipelines assets. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil prices have become less volatile over the past couple of years which has resulted in oil sands producers recommencing projects that had been previously cancelled or deferred, creating increased demand in the WCSB for new pipeline infrastructure.

Also, shippers are not required to enter into long-term shipping commitments on Enbridge s mainline system; rather, monthly volume nominations are accepted. The Company s existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. The ITS and Terrace Agreement as well as the Southern Access and Alberta Clipper agreements on the Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection on its base or Terrace systems, but does on its SEP II, Southern Access and Alberta Clipper expansions.

Competition

Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition also arises from new pipeline proposals that provide access to market areas currently served by the Company s liquids pipelines. One such competing project began commercial operations in early 2010 and will serve markets at Wood River, Illinois and Cushing, Oklahoma. This pipeline has an initial capacity of 435,000 bpd and an ultimate stated capacity of 591,000 bpd. Commercial support has also been announced to construct additional ex-Alberta capacity of 500,000 bpd to Nederland, Texas, for an in-service date during 2013. Competing alternatives for delivering western Canadian liquid hydrocarbons into the United States or other markets could erode shipper support for current or future expansion. However, the Company believes that its liquids pipelines provide attractive options to producers in the WCSB due to its competitive tolls and multiple delivery and storage points. Increased competition could arise from new feeder systems servicing the same geographic regions as the Company s feeder pipelines.

The Company continues to adapt to the changes in its business environment. Enbridge is committed to performance excellence and is focused on becoming more efficient, more collaborative, more innovative and more cost effective so that the Company can pass those benefits on to its customers through service, savings, reliability and responsiveness.

Potential Pressure Restrictions

The Company s liquids systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of a pipeline is indefi nitely long; however, as pipelines age the level of expenditures required for inspection and maintenance may increase. Pressure restrictions may from time to time be established on the Company s pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. While the Enbridge System is volume-protected, EEP s Lakehead System and certain other pipelines would be adversely affected by any pressure restrictions that do reduce volumes transported. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs.

Regulation

The Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from those operations. A portion of the Enbridge System and other liquids pipelines earnings are affected by changes in market interest rates. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS, which govern the majority of the segment s assets.

National Energy Board Decision

In October 2009, the NEB released a decision stating the generic multi-pipeline formula used to determine allowed ROE for pipeline companies is no longer in effect. The formula will not be replaced; instead returns will be determined through negotiated settlement between shippers and pipelines. As the formula is referenced in some current industry settlements, the NEB will continue to publish the generic ROE for 2010 and 2011, and if requested will continue to publish it post-2011.

Certain of the Company s Liquids assets are regulated by the NEB and reference the multi-pipeline rate. The Company does not expect there will be a material financial impact as a result of this decision.

Gas Distribution

EARNINGS

(millions of Canadian dollars)	**2010**	2009	2008
Enbridge Gas Distribution (EGD)	**135**	129	123
Other Gas Distribution and Storage	**32**	25	18
Adjusted Earnings	**167**	154	141
EGD (warmer)/colder than normal weather	**(12)**	17	23
EGD impact of tax rate changes		21	
EGD interest income on GST refund		7	
EGD provision for one time charges			(3)
Other Gas Distribution and Storage asset impairment loss		(10)	
Other Gas Distribution and Storage adoption of new accounting standard		(3)	
Earnings	**155**	186	161

Adjusted earnings from Gas Distribution were $167 million for the year ended December 31, 2010 compared with $154 million for 2009 and $141 million for 2008. The increase in Gas Distribution adjusted earnings primarily resulted from continuing higher contributions from EGD under its Incentive Regulation (IR) arrangement and modest growth in the Company s other gas distribution businesses.

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting items:

- EGD earnings are adjusted to reflect the impact of weather.
- In 2009, earnings from EGD reflected the impact of favourable tax rate changes.
- Earnings from EGD for 2009 included interest income of $7 million related to the recovery of excess GST remitted to Canada Revenue Agency.
- Earnings from EGD for 2008 included a $3 million provision for one-time charges to better align certain operating practices with its strategy under IR.

- Other Gas Distribution and Storage earnings for 2009 reflected a $10 million asset impairment loss which included goodwill.

- Other Gas Distribution and Storage 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.

ENBRIDGE GAS DISTRIBUTION

EGD is Canada s largest natural gas distribution company and has been in operation for more than 160 years. It serves approximately 2.0 million customers in central and eastern Ontario and parts of northern New York State. EGD s utility operations are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission.

Incentive Regulation

In 2007, the Company filed a rate application with the OEB requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the IR Settlement Agreement (the IR Framework) with customer representatives.

The objectives of the IR Framework are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to its customers.

Under the IR Framework, Enbridge is allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps must be shared with customers on an equal basis. Enbridge estimates the customer portion of 2010 earnings over the allowed threshold to be $19 million (2009 $19 million).

Rate Adjustment Applications

In September 2010, EGD filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

In September 2009, EGD filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Subsequent to filing a settlement agreement with ratepayer groups with the OEB, in March 2010 EGD received approval of a fiscal 2010 final rate order from the OEB. The 2010 final rate order approved the implementation of a rate change effective April 1, 2010, which enabled EGD to recover the approved revenues as if rates were effective January 1, 2010.

Results of Operations

Adjusted earnings for the year ended December 31, 2010 were $135 million compared with $129 million for the year ended December 31, 2009. The increase in EGD adjusted earnings was primarily a result of continued favourable performance under IR, reflecting customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation expense. Depreciation expense increased due to a higher overall asset base, including the implementation of a new customer billing system in late 2009.

Adjusted earnings for the year ended December 31, 2009 were $129 million compared with $123 million for the year ended December 31, 2008. The increase in EGD s adjusted earnings was primarily due to customer growth and lower interest expense, offset by higher operating costs and estimated accrued earnings sharing with customers under the current IR term caused primarily by a reduced rate base resulting from lower cost gas in storage.

EGD earnings were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for each period are adjusted to reflect the impact of weather. Weather is a significant driver of delivery volumes given that a significant portion of EGD customers use natural gas for space heating.
- In 2009, earnings reflected the impact of favourable tax rate changes.
- Earnings for 2009 included interest income of $7 million related to the recovery of excess GST remitted to Canada Revenue Agency.
- Earnings from 2008 included a $3 million provision for one-time charges to better align certain operating practices with its strategy under IR.

Business Risks

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

Regulatory Risk

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB s risk assessment of EGD for the 2007 fiscal year.

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario s regulated utilities. The new policy guidelines forecasted a new base level ROE of approximately 9.85% for EGD s 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, EGD applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, EGD anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, EGD has appealed the OEB s May 2010 decision to the Ontario Divisional Court. The Company s appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

The IR Framework allows certain categories of expense, from a cost of service view, and uncontrollable external factors, which will permit EGD to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The settlement also includes a mechanism to reassess the IR plan and return to cost of service if there are signifi cant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the settlement mitigate EGD s risk to factors beyond management s control.

Natural Gas Cost Risk

EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow EGD to recover or refund the natural gas cost differential. EGD has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB. However, the cost of natural gas does affect the amount of EGD s investment in gas in storage on which it earns a rate base return. Consequently, a lower gas price will reduce EGD s earnings.

Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, EGD s ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD s customer base uses natural gas for space heating. For the years ended December 31, 2010, 2009 and 2008, (warmer)/colder than normal weather resulted in a reduction to earnings of $12 million and an increase to earnings of $17 million and $23 million, respectively.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% (2009 81%; 2008 79%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the average use true-up variance account that was established under the IR Framework. This variance account enables recovery from or repayment to customers of amounts representing variances in the actual and forecast average use by general service customers. EGD remains at risk of distribution volumes for large volume contract commercial and industrial customers.

OTHER GAS DISTRIBUTION AND STORAGE

Other Gas Distribution includes natural gas distribution utility operations in Quebec, and New Brunswick, the most significant being Enbridge Gas New Brunswick (EGNB) (100% owned and operated by the Company), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 11,000 customers. Approximately 790 kilometres (490 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

Results of Operations

Other Gas Distribution and Storage adjusted earnings were $32 million for the year ended December 31, 2010, compared with $25 million for the year ended December 31, 2009 and $18 million for the year ended December 31, 2008, primarily due to an increased contribution from Enbridge s Ontario unregulated gas storage business and from franchise growth at EGNB.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB s cost of service exceeds its distribution revenues. The EUB has approved the deferral of the shortfall between distribution revenues and the cost of service during the development period for recovery in future rates. The recovery period is expected to start in 2013 and end no sooner than December 31, 2040. On December 31, 2010, the regulatory deferral asset was $171 million (2009 $155 million).

Other Gas Distribution and Storage earnings were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for 2009 reflected a $10 million asset impairment loss which included goodwill.
- Other Gas Distribution and Storage 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.

Gas Pipelines, Processing and Energy Services

EARNINGS

	2010	2009	2008
(millions of Canadian dollars)			
Enbridge Offshore Pipelines (Offshore)	**23**	29	7
Alliance Pipeline US	**25**	27	25
Vector Pipeline	**15**	16	14
Aux Sable	**37**	26	28
Energy Services	**20**	29	17
Other	**3**	(11)	50
Adjusted Earnings	**123**	116	141
Offshore property insurance recoveries from hurricanes	**2**	4	
Alliance Pipeline US shipper claim settlement			2
Aux Sable unrealized derivative fair value gains/(losses)	**7**	(36)	56
Aux Sable loan forgiveness		7	
Energy Services unrealized derivative fair value gains/(losses)	**(12)**	3	23
Energy Services Lehman and SemGroup credit recovery/(loss)	**1**	1	(6)
Other gain on sale of investments		329	561
Other impact of tax rate changes		4	
Other asset impairment loss			(10)
Earnings	**121**	428	767

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $123 million for the year ended December 31, 2010 compared with $116 million for the year ended December 31, 2009, primarily resulting from contributions from Aux Sable and the Company s green energy investments.

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $116 million for the year ended December 31, 2009 compared with $141 million for the year ended December 31, 2008. The decreased adjusted earnings were substantially due to the sale of the Company s International investments, offset by higher volumes within Offshore and favourable foreign exchange rates.

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

- Offshore earnings included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.
- Earnings for the year ended December 31, 2008 were impacted by $2 million in proceeds received by Alliance Pipeline US from the settlement of a claim against a former shipper which repudiated its capacity commitment.
- 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.
- Earnings for the year ended December 31, 2009 from Aux Sable reflected a $7 million gain from a loan forgiveness related to a negotiated settlement with a counterparty in bankruptcy proceedings.
- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of inventory and the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions.
- Energy Services earnings for the year ended December 31, 2008 included a $6 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. In 2009, $1 million was recovered from SemGroup and in 2010 the Company received a partial recovery of $1 million from the sale of its receivable from Lehman Brothers.
- In March 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. In June 2008, the Company sold its investment in CLH for proceeds of $1,380 million, resulting in a gain of $556 million. A $5 million gain on sale of investment in Inuvik Gas was also reflected in earnings from Other in 2008.
- Other earnings for 2009 reflected the impact of $4 million in favourable tax rate changes.
- An impairment loss arising from the write-off of goodwill related to the Company s Ontario Wind power assets was included in Other earnings in 2008.

ENBRIDGE OFFSHORE PIPELINE

Offshore is comprised of 13 natural gas gathering and FERC-regulated transmission pipelines and one oil pipeline in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 1,500 miles (2,400 kilometres) of underwater pipe and onshore facilities and transported approximately 2.2 bcf/d during 2010. Offshore currently moves approximately 50% of offshore deepwater gas production through its systems in the Gulf of Mexico.

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease s maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current deliverability expectations.

The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

The business model utilized on a go forward basis and included in the WRGGS and Big Foot commercially secured projects differs from the historic model. These new projects have a base level return which is locked in by take or pay commitments. If volumes reach producer anticipated levels the return on these projects will increase. In addition, Enbridge has minimal capital cost risk on these projects and commercial agreements continue to contain life-of-lease commitments.

Results of Operations

Adjusted earnings from Offshore for the year ended December 31, 2010 were $23 million compared with $29 million for the year ended December 31, 2009. The Company experienced volume declines due to the slower regulatory permitting process. In July 2010, the Secretary of the Interior suspended deepwater drilling. Subsequently, in October 2010, the deepwater drilling suspension was lifted, allowing a return to deepwater drilling, but subject to increased regulation and approval. Other factors contributing to the adjusted earnings decrease were higher operating and administrative costs, including insurance and higher depreciation expense.

Offshore adjusted earnings for the year ended December 31, 2009 were $29 million compared with $7 million for the year ended December 31, 2008. This increase was due to higher volumes, including contributions from Shenzi, since its in-service date in April 2009, and Thunder Horse, since its in-service date of June 2008, as well as favourable foreign exchange rates. Offshore adjusted earnings for 2009 included $4 million in insurance proceeds collected during the second and fourth quarters, which were partial reimbursement for business interruption lost revenues and operating expenses associated with Hurricane Ike in 2008.

Earnings for 2010 and 2009 included insurance proceeds of $2 million and $4 million, respectively, related to the replacement of damaged infrastructure as a result of the 2008 hurricane.

Business Risks

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

Weather

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

Reflecting improved insurance market pricing terms, effective June 2010, Offshore s insurance policy now again includes coverage related to named windstorms, such as hurricanes, for all systems except for the Stingray Pipeline system. As a result of the change in coverage, physical damage caused by hurricanes will not impact Offshore s financial performance to the extent it otherwise would. On June 1, 2009, Offshore had chosen to eliminate this coverage due to significant increases in insurance premiums and deductibles as a result of the hurricanes that had taken place in the Gulf in previous years. As part of a 2009 FERC rate case settlement, the Stingray Pipeline system implemented an event surcharge mechanism to allow recovery from shippers for hurricane damage.

Competition

There is competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the Neptune crude oil lateral and the recently announced Big Foot Oil Pipeline. Given rates of decline, offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of Offshore s transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates are subject to challenge from time-to-time.

The Gulf of Mexico events of 2010 have altered the offshore regulatory environment. Although the moratorium on deepwater drilling was lifted, future deepwater drilling activity will be subject to heightened regulation and oversight. Increased regulation may impact the levels and timing of future exploration and drilling activity in the region and the resultant production volumes available to ship on the Company s offshore system. The shifting business environment could result in increases in available capacity, resulting in heightened competition.

Other Risks

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing, changes in plans by shippers and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners, through cost of service tolling arrangements and pre-arranged terms in commercial agreements. Start-up delays are mitigated by the right to collect stand-by fees.

ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and United States portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have firm service shipping contract capacity to deliver 1.365 bcf/d and 1.325 bcf/d, respectively. Enbridge owns 50% of Alliance Pipeline US, while EIF, described under *Sponsored Investments*, owns 50% of Alliance Pipeline Canada.

Alliance connects with Aux Sable, of which Enbridge owns 42.7%, a NGLs extraction and fractionation facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada.

In September 2010, the Septimus Pipeline, a gathering pipeline owned by Aux Sable, was connected to a new receipt point on Alliance Pipeline Canada. This pipeline, with initial volumes of 20 million cubic feet per day (mmcf/d), sources liquids-rich gas from the Montney region. In 2009, Prairie Rose Pipeline, a gathering pipeline owned by a third party, was connected to a new gas receipt point on Alliance near Towner, North

Dakota. This pipeline brings in associated rich gas from the Bakken formation on to Alliance. The new receipt point went into service in January 2010, with an initial firm transportation capacity of 40 mmcf/d, which will increase to 80 mmcf/d in 2011.

Transportation Contracts

Alliance Pipeline US has long-term, take-or-pay contracts to transport 1.345 bcf/d of natural gas or 98.5% of the total contracted capacity. Primary contract terms ending on December 1, 2015 are for 1.305 bcf/d, while contracts for 0.040 bcf/d have a contract term ending February 1, 2020. Alliance Pipeline US has an additional 20 mmcf/d of natural gas which is currently being contracted on a short term basis. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 10.88%. Each long-term contract had the option of being renewed upon notice by November 30, 2010 for successive one-year terms beyond the original 15-year primary term. As noted below, shippers representing 8% of contracted capacity elected to extend their commitments. Alliance Pipeline US operations are regulated by the FERC.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense in the financial statements is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the financial statement amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, that began being recovered from shippers, starting in 2009 for Alliance Pipeline US and 2012 for Alliance Pipeline Canada. As at December 31, 2010, $122 million (US$123 million) (2009 - $151 million (US$144 million)) was recorded as deferred transportation revenue for Alliance Pipeline US.

Alliance Pipeline Recontracting

In December 2010, shippers representing 8% of contracted capacity on the Alliance System elected to extend their existing contracts from December 1, 2015 to at least December 1, 2016. These shippers also retained the option of continuing to extend their capacity commitments on an annual basis. Remaining shippers, representing the balance of originally contracted capacity, have elected not to extend their commitments beyond 2015 under the terms of the original contracts. Alliance Pipeline US is entitled to additional compensation, in the form of accelerated depreciation recovered, from those shippers who have not elected to extend their contracts beyond 2015.

Currently, Alliance continues to be fully contracted on a firm service basis and is expected to run at or near full capacity for the foreseeable future given its geographic positioning and high pressure operating capability to move valuable liquids rich gas to market. Over the next five years, Alliance is expected to transition from a single-service, single toll export pipeline to a new multi-service business model, providing customers with a choice from an assortment of transportation services. Among other things, Alliance will seek to implement short-haul delivery and receipt services to complement its existing bullet line delivery service to Chicago and seek to provide greater shipper market liquidity through hub services. Also, Alliance is well placed to benefit from incremental unconventional volumes from shale gas plays in British Columbia, and is currently evaluating opportunities to expand its service offerings in this area. Rates for Alliance s long haul service are expected to be favourable compared to other alternatives for reaching United States Midwest and eastern Canada markets.

Results of Operations

Alliance Pipeline US adjusted earnings were $25 million for the year ended December 31, 2010, comparable with $27 million for the year ended December 31, 2009 and $25 million for the year ended December 31, 2008.

Earnings for the year ended December 31, 2008 included $2 million in proceeds received from the settlement of a claim against a former shipper which repudiated its capacity commitment.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago, Illinois to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.3 bcf/d and is operating at or near capacity.

Vector Pipeline s primary sources of supply are through interconnections with Alliance and the Northern Border Pipeline in Joliet, Illinois. The total long haul capacity of Vector is approximately 87% committed through 2015. Approximately 55% of the long haul capacity is committed through firm transportation contracts at rates negotiated with the shippers and approved by the FERC; with the remaining capacity sold at market rates. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector Pipeline is an interstate natural gas pipeline with FERC and NEB approved tariffs establishing rates, terms and conditions governing its service to customers. On the United States portion of Vector, tariff rates are determined using a cost of service methodology and tariff changes may only be implemented upon approval by the FERC. For 2010, the FERC approved maximum tariff rates include an underlying weighted average after-tax ROE component of 11.18% (2009 - 11.07%; 2008 - 11.04%). On the Canadian portion, Vector Pipeline is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2010, maximum tariff tolls include a ROE component of 10.48% after-tax.

Results of Operations

Vector Pipeline earnings were $15 million for the year ended December 31, 2010, comparable with $16 million for the year ended December 31, 2009 and $14 million for the year ended December 31, 2008.

Business Risks

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

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending primarily to 2015. Alliance Pipeline US is also well positioned to deliver incremental liquids-rich gas production from new developments in the Montney and Bakken regions. Vector Pipeline s interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll. Demand is supported by rising use of gas for power generation.

Exposure to Shippers

The failure of shippers to perform their contractual obligations could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper s credit position not meet tariff requirements. These pipelines also have diverse groups of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance the competitive position of Alliance Pipeline US.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new supply sources and traditional low cost pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts, which expire starting in November 2015, for approximately 87% of its capacity. The remaining contracts expire at various times starting in April 2012. Certain long-term firm contracts (55% of capacity) provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term ending November 2015. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both the US portion of Vector Pipeline and Alliance Pipeline US operations are regulated by the FERC. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

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

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business, which owns and operates a plant near Chicago, Illinois at the terminus of Alliance Pipeline. The plant extracts NGLs from the liquids-rich natural gas transported on Alliance, as necessary to meet gas quality specifications of downstream transmission and distribution companies and to take advantage of positive commodity price spreads.

Aux Sable sells its NGLs production to BP under a long-term contract. BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel gas requirements of the Aux Sable plant and is responsible for the capacity on the Alliance Pipeline, held by an Aux Sable affiliate, at market rates. The BP agreement is for an initial term of 20 years, expiring December 21, 2025 and may be extended by mutual agreement for 10-year terms.

Results of Operations

Aux Sable adjusted earnings increased from $26 million in 2009 to $37 million in 2010 primarily due to enhanced plant performance and stronger fractionation margins.

Adjusted earnings for the year ended December 31, 2009 were $26 million compared with earnings of $28 million for the year ended December 31, 2008. Aux Sable adjusted earnings decreased due to unexpected plant outages during the fourth quarter of 2009.

Aux Sable earnings reflected the following non-recurring or non-operating adjusting items:

- Earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company s forward gas processing risk management position.
- Earnings for 2009 included a $7 million gain from a loan forgiveness related to a negotiated settlement with a counterparty in bankruptcy proceedings.

ENERGY SERVICES

Energy Services includes the Company s energy marketing businesses. Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers. This business involves buying, selling, transporting and storing crude oil and condensate. Tidal Energy transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, flexible pricing, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities can create modest commodity exposures. Any residual open positions created from this physical business are closely monitored and must comply with the Company s formal risk management policies.

Energy Services natural gas marketing services are provided by both Tidal Energy and Gas Services. Tidal Energy markets natural gas to optimize Enbridge s commitments on the Alliance and Vector pipelines. Capacity commitments at December 31, 2010 and 2009 were 33 mmcf/d on Alliance (3% of capacity) and 156 mmcf/d on Vector Pipeline (12% of capacity). Earnings from these commitments are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance, and between Chicago and Dawn, for Vector Pipeline. To the extent transportation costs exceed the basis (location) differential, earnings will be negatively affected. Tidal Energy also provides fee-for-service arrangements for third parties, leveraging its natural gas marketing expertise and access to transportation capacity. Gas Services markets natural gas to commercial and industrial customers in the upper mid-west area of the United States.

Results of Operations

Energy Services adjusted earnings decreased to $20 million for the year ended December 31, 2010 from $29 million in 2009 as a result of reduced volume and margin opportunities in liquids marketing.

Adjusted earnings from Energy Services increased from $17 million in 2008 to $29 million in 2009. The increase was due to higher volumes and the impact of realizing favourable storage and transportation margins.

Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items:

- Earnings for each period reflect 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.
- Earnings in 2008 included a $6 million receivable write-off related to SemGroup and Lehman Brothers bankruptcies. In 2009, $1 million was recovered from SemGroup and, in 2010 the Company received a partial recovery of $1 million from the sale of its receivable from Lehman Brothers.

OTHER

Other includes operating results from the Company s investments in green energy projects, including Ontario Wind and Sarnia Solar, net of business development expenses associated with international activities.

In 2009, the Company sold its 24.7% interest in OCENSA, a crude oil export pipeline in Colombia. In 2008, the Company sold its 25% equity interest in CLH, Spain s largest refined products transportation and storage business. Both of these investments were sold at very attractive prices and proceeds were utilized in the funding of the North American expansion projects discussed earlier. There are currently minimal operations in International; however, Enbridge continues to actively monitor the international business environment to identify potential new investment opportunities.

Results of Operations

For the year ended December 31, 2010, Other adjusted earnings were $3 million compared with an adjusted loss of $11 million for the year ended December 31, 2009 primarily reflecting positive contributions from the Sarnia Solar Project and reduced business development costs.

Other adjusted earnings decreased from $50 million in 2008 to an adjusted loss of $11 million in 2009 primarily resulting from the sale of OCENSA and CLH and higher business development expenditures.

Other earnings were impacted by the following non-recurring or non-operating adjusting items:

- In March 2009, the Company sold its investment in OCENSA for proceeds of $512 million, resulting in a gain of $329 million. In June 2008, the Company sold its investment in CLH for proceeds of $1,380 million, resulting in a gain of $556 million. A $5 million gain on the sale of investment in Inuvik Gas was also reflected in earnings in 2008.
- Other earnings for 2009 reflected the impact of $4 million in favourable tax rate changes.
- An impairment loss arising from the write-off of goodwill related to the Company s Ontario Wind power assets was included in earnings in 2008.

Sponsored Investments

EARNINGS

	2010	2009	2008
(millions of Canadian dollars)			
Enbridge Energy Partners (EEP)	**122**	99	60
Enbridge Energy, L.P. Alberta Clipper US (EELP)	**42**	7	
Enbridge Income Fund (EIF)	**45**	45	41
Adjusted Earnings	**209**	151	101
EEP leak remediation costs and lost revenue	**(106)**		
EEP unrealized derivative fair value gains/(losses)	**(1)**	(2)	6
EEP Lakehead System billing correction	**1**	4	
EEP dilution gain on Class A unit issuance	**36**		5
EEP asset impairment loss	**(2)**	(12)	
EEP impact of 2008 hurricanes and project write-offs			(2)
EIF Alliance Canada shipper claim settlement			1
Earnings	**137**	141	111

Adjusted earnings from Sponsored Investments were $209 million for the year ended December 31, 2010 compared with $151 million in 2009 and $101 million in 2008. The increase in adjusted earnings resulted primarily from increased contributions from EEP as a result of positive operating factors, including growth projects, as well as the Company s investment in EELP.

Sponsored Investments earnings were impacted by several non-recurring or non-operating adjusting items:

- Earnings from EEP included a charge of $103 million (net to Enbridge) related to estimated costs, before insurance recoveries, associated with the Line 6B and Line 6A crude oil releases as well as an impact of $3 million (net to Enbridge) related to period lost revenue as a result of the leaks.

See *EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

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

- 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 $36 million (2008 - $5 million) dilution gain (after-tax and non-controlling interest) because Enbridge did not participate in EEP s Class A unit offerings.

- EEP earnings for 2010 and 2009 included charges related to asset impairment losses.

- 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge s share was $2 million, as well as the write-off of costs on certain projects cancelled due to market conditions.

- Earnings from EIF for the year ended December 31, 2008 included proceeds of $1 million from the settlement of a claim against a former shipper on Alliance Canada which repudiated its capacity commitment.

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transportation and storage assets and natural gas gathering, treating, processing, transportation and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the United States; the Mid-Continent crude oil system consisting of an interstate crude oil pipeline and storage facilities; a crude oil gathering system and interstate pipeline system in North Dakota; and natural gas assets located primarily in Texas.

In September 2010, EEP acquired the entities that comprise the Elk City Gathering and Processing System (Elk City System) from Atlas Pipeline Partners for US$700 million. The Elk City System extends from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The Elk City System consists of approximately 1,290 kilometers (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 mmcf/d and a combined natural gas liquids production capability of 20,000 bpd.

In March 2008, Enbridge did not participate in EEP s issuance of Class A units, resulting in a $5 million dilution gain and a decrease in ownership interest from 15.1% to 14.6%. In late 2008, Enbridge purchased 16.3 million Class A common units of EEP, resulting in an ownership increase to 27.0%. The Company s average ownership interest in EEP during 2008 was 15.7%. At December 31, 2009, Enbridge s ownership interest in EEP remained at 27.0%. In June 2010, EEP entered into an Equity Distribution Agreement (EDA) for the issue and sale of its Class A units up to an amount of $150 million. During 2010, EEP issued 1.1 million Class A units under the EDA. Enbridge did not fully participate resulting in a dilution gain of $4 million. In November 2010, Enbridge did not participate in EEP s issuance of 6 million Class A units, resulting in a $32 million dilution gain and decreasing the Company s ownership to 25.5%. The Company s average ownership interest in EEP during 2010 was 26.7%.

Distributions

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

	Unitholders including Enbridge	GP Interest
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First target $0.59 per unit up to $0.70 per unit	85%	15%
Second target $0.70 per unit up to $0.99 per unit	75%	25%
Over second target cash distributions greater than $0.99 per unit	50%	50%

In the first two quarters of 2008 EEP paid quarterly distributions of $0.95 per unit, and effective August 2008, EEP increased quarterly distributions to $0.99 per unit, which remained in effect through the first quarter of 2010. Effective April 2010, EEP increased the quarterly distributions to $1.0025 per unit. In July 2010, EEP further increased the quarterly distributions to $1.0275 per unit. Of the $122 million Enbridge recognized as adjusted earnings from EEP during 2010, 27% (2009 27%; 2008 37%) were GP incentive earnings while 73% (2009 73%; 2008 63%) were Enbridge s limited partner share of EEP s earnings.

In spite of the challenges posed by the crude oil releases on EEP s Lakehead System, EEP believes it has sufficient liquidity to fund operating activities and environmental remediation obligations while maintaining its present distribution rate to EEP unitholders.

Results of Operations

After adjusting EEP earnings for non-recurring or non-operating items, including the impact of the Line 6B and Line 6A crude oil releases, EEP adjusted earnings increased to $122 million for the year ended December 31, 2010 compared with $99 million for the year ended December 31, 2009. The increase was 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 and increased average transportation rates, partially offset by increased operating costs.

Adjusted earnings from EEP were $99 million for the year ended December 31, 2009 compared with $60 million for the year ended December 31, 2008. EEP adjusted earnings increased due to the Company s higher ownership interest in EEP resulting from the December 2008 Class A unit subscription; an increased contribution due to additional assets placed in service and related tariff surcharges for recent expansions; higher incentive income; and a more favourable foreign exchange rate used to translate EEP s earnings to Canadian dollars.

EEP earnings were impacted by several non-recurring or non-operating adjusting items:

- Earnings from EEP included a charge of $103 million (net to Enbridge) related to estimated costs, before insurance recoveries, associated with the Line 6B and Line 6A crude oil releases as well as an impact of $3 million (net to Enbridge) related to period lost revenue as a result of the leaks. See *EEP Lakehead System Line 6B and 6A Crude Oil Releases.*
- Earnings included a change in the unrealized fair value on derivative financial instruments in each year.
- 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 for 2010 and 2009 included charges related to asset impairment losses.
- 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge s share was $2 million, as well as the write-off of costs on certain projects cancelled due to market conditions.

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

Enbridge holds an approximate 25.5% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Leak

On July 26, 2010, a crude oil release on Line 6B of EEP s Lakehead System was reported near Marshall, Michigan. EEP currently estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The 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 previously estimated 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. EEP subsequently revised its estimate from US$430 million to US$550 million ($96 million after-tax net to Enbridge) based on a review of costs and commitments incurred, as well as additional information concerning the requirements for environmental restoration and remediation. The assumptions made including the scope of remediation efforts, the duration that resources will be required to complete the work, weather conditions and other similar factors underlying EEP s estimates are subject to further modification and could result in additional revisions to EEP s estimates. Although EEP met the deadlines established by the Environmental Protection Agency (EPA) for clean up and remediation of areas affected by the crude oil release, it has the potential of incurring additional costs in connection with this incident, including fines and penalties.

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, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. 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 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 assumptions or in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

Insurance Recoveries

The Company maintains commercial liability insurance coverage that is consistent with coverage considered customary for its industry. The commercial liability insurance covers costs associated with environmental incidents such as those incurred for the leaks from Line 6B and 6A, excluding costs for fines and penalties. EEP is included in Enbridge s comprehensive insurance program that has an aggregate limit of US$650 million of pollution liability through the policy renewal date of May 1, 2011. The remaining coverage under the Company s existing insurance policies is approximately US$70 million. The Company does not maintain insurance coverage for interruption of operations except for water crossings; therefore, EEP will not recover approximately US$16 million of revenues lost while Line 6B and 6A were not in service.

Apart from the amounts for which EEP is not insured, it is anticipated that substantially all of the costs incurred from the leaks will ultimately be recoverable under the Company s existing insurance policies. EEP expects to record a receivable for any amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery is 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 is remediating on 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 6B and Line 6A incidents. Currently, approximately 20 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B 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 a United States state court. The Company believes this action or claim has been resolved pursuant to an agreed interim order.

ENBRIDGE ENERGY, L.P. ALBERTA CLIPPER US

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The Company funded 66.7% of the project s equity requirements through EELP, while 66.7% of the debt funding was made through EEP. EELP Alberta Clipper US earnings are the Company s earnings from its investment in EELP which undertook the project and represented AEDC recognized while the project was under construction. The Alberta Clipper Project was placed into service on April 1, 2010.

Results of Operations

Adjusted earnings from EELP Alberta Clipper US were $42 million for the year ended December 31, 2010 compared with $7 million for the year ended December 31, 2009. These 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 Alberta Clipper. Earnings were attributable to AEDC recognized while the project was under construction as well as tolls since Alberta Clipper went into service on April 1, 2010.

Business Risks

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

Competition

EEP s Lakehead System, the United States portion of the Enbridge System, is a major crude oil export route from the WCSB. Other existing competing carriers and pipeline proposals to ship western Canadian liquids hydrocarbons to markets in the United States represent competition for the Lakehead System. Further details on such competing projects are described within Business Risks under *Liquids Pipelines.* EEP s Mid-Continent system and North Dakota system also face competition from existing competing pipelines, proposed future pipelines, and alternative gathering facilities available to producers or the ability of the producers to build such gathering facilities. Competition for EEP s storage facilities include large integrated oil companies and other midstream energy partnerships.

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

Supply and Demand

The profitability of EEP depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP s Lakehead System depends primarily on the supply of western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada.

EEP s natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Volume Risk

A decrease in volumes transported by EEP s systems can directly and adversely affect revenues and results of operations. A decline in volumes transported can be influenced by factors beyond EEP s control including: competition, regulatory action, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems.

Regulation

In the United States, the interstate oil pipelines owned and operated by EEP and certain activities of EEP s intrastate natural gas pipelines are subject to regulation by the FERC or state regulators and its revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

Market Price Risk

EEP s gas processing business is subject to commodity price risk for natural gas and NGLs. These risks have been managed by using physical and financial contracts, fixing the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP s earnings are exposed to associated mark-to-market valuation changes.

ENBRIDGE INCOME FUND

EIF s primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of Alliance previously described in the *Gas Pipelines, Processing and Energy Services* segment. The Saskatchewan System owns and operates crude oil and liquids pipelines systems in southern Saskatchewan and southwestern Manitoba, connecting primarily with Enbridge s mainline pipeline to the United States. In December 2010, Phase II of the Saskatchewan System Capacity Expansion was completed, increasing capacity across the system by approximately 125,000 bpd.

EIF also owns interests in three wind power generation projects purchased from Enbridge in October 2006 and a business that operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Corporate Restructuring

On December 17, 2010, a plan of arrangement (the Plan) to restructure EIF took effect. Under the Plan all publicly held trust units and 5 million units held by Enbridge, were exchanged on a one-for-one basis for shares of a taxable Canadian corporation, EIFH. The business of EIFH is limited to investment in EIF. In connection with this exchange, Enbridge as holder of Enbridge Commercial Trust (ECT) Preferred Units was granted a right of exchange whereby Enbridge may exchange such ECT Preferred Units for EIF Trust Units on a one-for-one basis. Concurrently, the liquidity right which provided Enbridge as the holder of ECT Preferred Units the option to request redemption was terminated.

The Company retained its overall 72% economic interest in EIF and is the primary beneficiary of EIF both before and after the Plan through a combined direct and indirect investment in EIF voting units and a non-voting preferred unit investment. As such, Enbridge consolidates EIF under variable interest entity accounting rules.

Incentive and Management Fees

Enbridge receives a base annual management fee for management services provided to EIF, plus incentive fees. Incentive fees paid to Enbridge prior to the December 17, 2010 restructuring of EIF were equal to 25% of annual cash distributions over $0.825 per unit. Following the restructuring of EIF, the incentive fee payable per the Management Agreement was modified to approximate the incentive fee calculation prior to the restructuring. In 2010, the Company received incentive fees of $8 million (2009 $8 million; 2008 $5 million) before income taxes.

Enbridge also provides management services to EIFH. No additional fee will be charged to EIFH for these services.

Results of Operations

Adjusted earnings from EIF were $45 million for both the year ended December 31, 2010 and 2009. Adjusted earnings from EIF reflected growth attributable to Phase II of the Saskatchewan System Capacity Expansion, which was placed into service in December 2010, offset by a reduced contribution from the wind power assets and increased corporate costs related to the Corporate Restructuring completed in December 2010. EIF s interest in Alliance Pipeline Canada continued to contribute stable adjusted earnings in both 2010 and 2009.

Adjusted earnings from EIF were $45 million for the year ended December 31, 2009 compared with adjusted earnings of $41 million for the year ended December 31, 2008. EIF adjusted earnings primarily reflected growth in Saskatchewan System earnings attributable to customer connections and expansions completed in 2008, partially offset by increased income taxes and corporate costs compared with 2008.

Earnings from EIF for 2008 included proceeds of $1 million from the settlement of a claim against a former shipper on Alliance Pipeline Canada which repudiated its capacity commitment.

Business Risks

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

Competition

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers and thereby potentially reduce shipping on the Saskatchewan System or result in possible toll reductions. The Saskatchewan System manages exposure to loss of shippers by ensuring the shipping rates are competitive and by providing a high level of service. Further, the Saskatchewan System s right-of-way and expansion efforts have created a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies through its expansion projects in order to meet its shippers growing demand.

Regulation

EIF s 50% interest in Alliance Pipeline Canada and certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of EIF.

Demand for Services

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are, in general, based on volumes transported and are on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

Corporate

EARNINGS

(millions of Canadian dollars)	**2010**	2009	2008
Noverco	**21**	19	20
Corporate	**(48)**	(39)	(58)
Adjusted Loss	**(27)**	(20)	(38)
Noverco impact of tax rate changes		6	
Corporate unrealized derivative fair value gains	**25**	207	26
Corporate unrealized foreign exchange gains on translation of intercompany balances, net	**40**	133	
Corporate gain on sale of investment in NTP		25	
Corporate impact of tax rate changes		4	
Corporate gain on sale of corporate aircraft			5
Corporate U.S. pipeline tax decision			(32)
Corporate asset impairment loss			(7)
Earnings/(Loss)	**38**	355	(46)

Total adjusted loss from Corporate was $27 million for the year ended December 31, 2010 compared with $20 million for the year ended December 31, 2009. The increase in adjusted loss was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increased adjusted loss included higher administrative costs and higher interest costs, partially offset by an increased corporate income tax recovery.

Total adjusted loss from Corporate was $20 million for the year ended December 31, 2009 compared with $38 million for the year ended December 31, 2008. The improvement in Corporate adjusted loss is the result of foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances as the result of a stronger United States dollar, partially offset by higher administrative costs, including compensation, and an increase in bank stand-by fees reflecting tighter credit markets.

Corporate earnings/(loss) was impacted by the following non-recurring or non-operating adjusting items:

- Noverco earnings for 2009 included a $6 million benefit related to favourable tax rate changes.
- Earnings for each year included the change in the unrealized fair value gains 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.
- In May 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 year ended December 31, 2009 included a $4 million benefit related to favourable tax rate changes.
- A $5 million gain on the sale of a corporate aircraft is included in Corporate costs for the year ended December 31, 2008.
- An unfavourable court decision related to the tax basis of previously owned United States pipeline assets resulted in the recognition of a $32 million income tax expense in the year ended December 31, 2008.
- Earnings in 2008 included an asset impairment loss arising from the write-off of goodwill related to the Company s investment in NSolv, a technology development venture.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the states of New England. Gaz Metro became a privately held limited partnership as a result of a reorganization of its publicly held partnership units, which were exchanged on a one for one basis for common shares in Valener Inc., a new publicly listed corporation. The reorganization was effective September 30, 2010.

The Company announced on February 3, 2011 that it will invest $145 million to acquire an additional 6.8% interest in Noverco from Laurentides Investissements (SAS), a subsidiary of GDF SUEZ, bringing its total interest in Noverco to 38.9%. Trencap, a partnership managed by the Caisse de Depot et Placement du Quebec, will acquire Laurentides Investissements remaining 10.8% interest in Noverco, following which Enbridge and Trencap will become the sole shareholders of Noverco. The transaction is expected to close later in the year once all regulatory approvals have been received.

Weather variations do not affect Noverco s earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company s earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

Results of Operations

Noverco adjusted earnings were $21 million for the year ended December 31, 2010 comparable with $19 million for the year ended December 31, 2009 and $20 million for the year ended December 31, 2008. Noverco earnings for each year reflected stable contributions from the Company s preferred share investment and Noverco s underlying gas distribution investments.

CORPORATE

Corporate consists of the new business development activities, general corporate investments and financing costs not allocated to the business segments.

Results of Operations

Adjusted loss from Corporate was $48 million for the year ended December 31, 2010 compared with $39 million for the year ended December 31, 2009. The increase was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increase included higher administrative costs and higher interest costs, partially offset by an increased income tax recovery.

Adjusted loss from Corporate was $39 million for the year ended December 31, 2009 compared with $58 million for the year ended December 31, 2008. The improvement in Corporate adjusted loss is a result of foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances as the result of a stronger United States dollar, partially offset by higher administrative costs, including compensation, and an increase in bank stand-by fees reflecting tighter credit markets.

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 December 31, 2010, excluding the Southern Lights project financing, the Company had $5,848 million of committed credit facilities of which $3,316 million was drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $182 million, the Company had net available liquidity at December 31, 2010 of $2,714 million. The net available liquidity is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and optimize pricing and other terms. The following table provides details of the Company s credit facilities at December 31, 2010.

	Expiry Dates2	Total Facilities	Credit Facility Draws3	Available
(millions of Canadian dollars)				
Liquids Pipelines	**2012**	**200**	**26**	**174**
Gas Distribution	**2011 2012**	**717**	**334**	**383**
Sponsored Investments	**2012**	**300**	**130**	**170**
Corporate	**2012 2014**	**4,631**	**2,826**	**1,805**
		5,848	**3,316**	**2,532**
Southern Lights project financing 1	**2012 2014**	**1,697**	**1,504**	**193**
Total Credit Facilities		**7,545**	**4,820**	**2,725**

1 *Total facilities inclusive of $60 million for debt service reserve letters of credit.*
2 *Includes $30 million in demand facilities with no maturity date.*
3 *Includes facility draws, letters of credit and commercial paper issuances that are backstopped by the credit facility.*

The Company s credit facility agreements include standard default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As in prior years, the Company expects to continue to comply with these provisions and therefore not trigger any early repayments. As at December 31, 2010, the Company was in compliance with all debt covenants.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The Company s debt to capitalization ratio at December 31, 2010, including short-term borrowings but excluding non-recourse debt, was 65.0%, compared with 63.6% at the end of 2009. Including all debt, the capitalization ratio was 66.7% at December 31, 2010 compared with 66.1% at December 31, 2009.

The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. Short-term investments were $99 million at December 31, 2010 (2009 $143 million).

Excluding current maturities of long-term debt, the Company has a positive working capital position, consistent with December 31, 2009.

(millions of Canadian dollars	**2010**	2009
Cash and cash equivalents 1	**242**	327
Accounts receivable and other	**2,706**	2,484
Inventory	**813**	784
Short-term borrowings	**(326)**	(508)
Accounts payable and other	**(2,688)**	(2,463)
Interest payable	**(117)**	(104)
Working capital	**630**	520

1 Includes short-term investments, restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

Changes in commodity prices impact accounts receivable and other, inventory and accounts payable and other within Energy Services and EGD.

OPERATING ACTIVITIES

Cash provided by operating activities for the year ended December 31, 2010 was $1,851 million compared with $2,017 million for the year ended December 31, 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. Variances in working capital balances, primarily due to changes in commodity prices and sales volumes within Energy Services as well as changes in natural gas prices at EGD, resulted in the decline in cash from operating activities in 2010 compared with 2009.

Cash provided by operating activities for the year ended December 31, 2009 was $2,017 million compared with $1,372 million for the year ended December 31, 2008. The increase was due to increased contributions from the Company s growth projects placed into service in 2009 and additional distributions from EEP as a result of the Company s increased ownership, as well as the positive impact of working capital variances.

There are no material restrictions on the Company s cash with the exception of proportionately consolidated joint venture cash of $48 million, which cannot be accessed until distributed to the Company, and cash in trust of $12 million for specific shipper commitments.

INVESTING ACTIVITIES

In 2010, cash used for investing activities was $2,674 million compared with $3,306 million in 2009, a decrease of $632 million. Cash used in investing activities included $2,357 million of additions to property, plant and equipment for the year ended December 31, 2010 and $3,225 of additions to property, plant and equipment for the year ended December 31, 2009. 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 also completed three acquisitions in 2010 resulting in a use of cash of $116 million.

Investing activities also include 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.

Cash used for investing activities for the year ended December 31, 2009 was $3,306 million compared with $2,853 million in 2008. Proceeds of $1,383 million on the sale of the Company s investment in CLH in 2008 partially offset the higher use of cash for property, plant and equipment additions as well as long-term investments.

Capital Expenditures and Investments

[redacted]	Actual 2010	[redacted]
	765	
	387	
	1,153	
	253	
	2,558	

1 Includes the Company s investment in sponsored vehicles.

The Company s capital expansion initiatives are described in *Growth Projects*. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $2,525 million during 2011 on maintenance and capital projects which are substantially secured. While consistent with or still in excess of longer term historic levels, the expected decline in 2011 expenditures relative to 2010 and 2009 reflects the completion of certain large multi-year construction projects. The Company expects to finance these expenditures through cash from operating activities and available liquidity. The Company may also raise capital through the monetization or disposition of selected assets, or through access to capital markets as required.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued by the Company to finance business acquisitions, investments in subsidiaries and long-term investments. Funds for debt retirements are generated through cash provided from operating activities as well as through the issuance of replacement debt.

FINANCING ACTIVITIES

In 2010, cash provided by financing activities was $749 million compared with $1,109 million and $1,840 million in 2009 and 2008, respectively. Significant financing activities included medium-term note issuances as follows:

- Enbridge $800 million (2009 $1,000 million)
- Enbridge Pipelines Inc. $900 million (2009 $500 million)
- EGD $400 million (2009 $nil)
- EIF $200 million (2009 $nil)

In 2010, the proceeds from these term note issuances were used in part to fund term note repayments of $600 million and net commercial paper and credit facility repayments of $347 million.

In 2008, the Company secured financing that is non-recourse to the Company specific to the Canadian and United States segments of the Southern Lights project. Net proceeds on Southern Lights financing were $14 million, $343 million and $1,238 million for the years ended December 31, 2010, 2009 and 2008.

Short-term borrowings are used primarily to finance near term working capital requirements, including inventory at EGD. In 2010, EGD had lower net repayments of short-term borrowings compared with 2009. Due to the decline in natural gas commodity prices in 2009 compared with 2008, and the resultant decline in cash needed to finance inventory requirements, the Company made net repayments on short term borrowings totaling $366 million in 2009.

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the year ended December 31, 2010, dividends declared were $648 million (2009 $555 million), of which $426 million (2009 $414 million) were paid in cash and reflected in financing activities. The remaining $222 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 year ended December 31, 2010 and December 31, 2009, 34% and 25%, respectively, of total dividends declared were reinvested.

Outstanding Share Data 1

[redacted]

1 Outstanding share data information is provided as at February 9, 2011.

On February 18, 2011, the Company s Board of Directors approved a recommendation that shareholders approve a two-for-one stock split at the Company s Annual and Special Meeting of Shareholders on May 11, 2011. If approved by shareholders on May 11, 2011, and subject to regulatory approvals, the record date for the stock split is expected to be May 25, 2011.

Contingencies and Commitments

UNITED STATES LEGAL AND REGULATORY PROCEEDINGS LINE 6A AND 6B INCIDENTS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B incidents; however, currently no penalties or fines have been assessed against EEP in connection with the incidents. In addition, a number of actions or claims have been filed against Enbridge, EEP or their affiliates in the United States federal and state courts in connection with these incidents. See *Sponsored Investments Enbridge Energy Partners EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

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 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. On January 7, 2011, the Court of Appeal dismissed EGD s motion, meaning the Superior Court s decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

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.

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $1,686 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 December 31, 2010, the Company had substantially met all funding commitments.

CONTRACTUAL OBLIGATIONS

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

[redacted]

1 *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*

2 *Approximately $646 million of these contracts are commitments for materials related to the construction of growth projects. Changes to the planned funding requirements, including cancellation, are dependent on changes to the related projects.*

3 Contracts totaling $80 million are within proportionately consolidated joint venture entities and contracts totaling $156 million are between the Company and proportionately consolidated joint venture entities.

4 Assumes only required payments will be made into the pension plans in 2011. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2010. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

Quarterly Financial Information [1]

[redacted]					
[redacted]	3,977	3,505	3,502	4,143	15,127
[redacted]	342	138	157	326	963
[redacted]	0.93	0.37	0.42	0.87	2.60
[redacted]	0.92	0.37	0.42	0.86	2.57
[redacted]	0.425	0.425	0.425	0.425	1.700

[redacted]

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.

EGD and the Company s other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resultant revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market price risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. In 2010, Corporate earnings were impacted by unrealized derivative fair value changes of a $26 million gain, an $88 million loss, a $39 million gain and a $48 million gain in the first, second, third and fourth quarters, respectively. Most comparably, earnings were negatively impacted by an unrealized derivative fair value loss of $43 million in the first quarter of 2009, and positively impacted by unrealized derivative fair value gains of $115 million, $102 million and $33 million for the second, third and fourth quarters of 2009, respectively. The revaluation of foreign-denominated intercompany loans impacts earnings each quarter, with most notable impacts being the recognition of gains of $68 million and $50 million in the second and third quarters of 2009.

Reflected in earnings for the third and fourth quarters of 2010 are leak remediation costs and lost revenue associated with the Line 6B and Line 6A crude oil releases in the amounts of $85 million and $21 million, respectively. Other significant items that impacted the quarterly results include a gain of $329 million on the disposition of the Company s investment in OCENSA in the first quarter of 2009.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company s capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects*.

Related Party Transactions

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

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, for the year ended December 31, 2010 are $332 million (2009 $342 million; 2008 $302 million) to EEP and $7 million (2009 $6 million; 2008 $6 million) to Vector Pipeline. At December 31, 2010, the Company has accounts receivable of $29 million (2009 $38 million) from EEP and nil (2009 $1 million) from Vector Pipeline.

The Company had provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty. At December 31, 2009, there was no amount outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance and Vector Pipeline. EGD is charged market prices for these services. For the year ended December 31, 2010, EGD was charged $42 million (2009 $42 million; 2008 $41 million) for services from Alliance Pipeline and $28 million (2009 $29 million; 2008 $27 million) from Vector Pipeline.

Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. For the year ended December 31, 2010, amounts purchased were $2 million (2009 $16 million; 2008 $52 million) and sales were nil (2009 $6 million; 2008 $7 million).

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services Inc. and Enbridge Gas Services (US) Inc., respectively, subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. For the year ended December 31, 2010, amounts paid to Alliance Pipeline Canada were $13 million (2009 $9 million; 2008 $9 million), amounts paid to Alliance Pipeline US were $9 million (2009 $7 million; 2008 $7 million) and amounts paid to Vector Pipeline were $10 million (2009 $16 million; 2008 $16 million).

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP. For the year ended December 31, 2010, amounts purchased were $151 million (2009 $80 million; 2008 $24 million) and sales were $3 million (2009 $7 million; 2008 $9 million).

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. At December 31, 2010, the Company had substantially met all funding commitments. Further information on this project is included in *Growth Projects*.

The Company funded 66.7% of the project s equity requirements through EELP, an equity investee. The Company also provided a $346 million (US$347 million) (2009 $282 million (US$270 million)) loan to EEP for debt financing related to the construction. At December 31, 2010, $334 million is included in Deferred Amounts and Other Assets with the remaining $12 million included in Accounts Receivable and Other (2009 $282 million included in Accounts Receivable and Other). The loan, denominated in United States dollars, bears interest based on variable short-term rates.

During the year the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $40 million (US$39 million) payable to the Company relating to its Series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which was effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million (2008 $12 million).

ENBRIDGE INCOME FUND HOLDINGS

In December 2010, EIFH entered into an agreement with Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of the Company, to provide management and administrative services to EIFH. EMSI also provides management and administrative services to EIF. Provided that EIF is paying a base fee to EMSI for the services received by EIF, there is no fee payable to EMSI by EIFH.

LAKEHEAD LINE 6B LEAK

In connection with the Lakehead Line 6B leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $18 million for the year ended December 31, 2010.

Risk Management and Financial Instruments

Enbridge s proven investment value proposition is based on maintaining a reliable and low risk business model. The Company has stable earnings that are substantially generated from regulated businesses with cost of service rate-making or unregulated business with long-term take-or-pay arrangements. More than 90% of the Company s revenues come from investment grade customers. Other risks, such as capital cost and inflation, are generally transferred to customers through contractual arrangements. In addition to contractually eliminating the majority of its business risk, the Company has formal risk management policies, procedures and systems designed to mitigate any residual risks, such as market price risk, credit risk and operational risk. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company s strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

MARKET PRICE RISK

The Company s earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company s share price (collectively, market price risk). Given the Company s desire to maintain a stable and consistent earnings profile, it has implemented a Market Price Risk Management Policy which outlines a risk management governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk sensitivity at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The philosophy behind this metric is to identify the potential risk to the Company s annual earnings target, taking into account the illiquidity of certain exposure positions. The Company s policy is to limit EaR to a maximum of 5% of the next 12 months of forecasted earnings. Earnings exposure to market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company s Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with the EaR limits are reported to the CFRMC and variances are remediated as necessary.

Various hedging programs have been put into place to help ensure that the residual market price risks remain within policy limits, and thus help provide the Company with a general stability of earnings over a short and medium term horizon. The following section summarizes the primary types of market price risks to which the Company is exposed, and outlines the financial derivative hedging programs implemented.

The following table summarizes the EaR as a percentage of forecast earnings from the main groups of market price risk after the impact of the Company s hedging programs. These EaR numbers are based on business conditions and hedging programs as of December 31, 2010 and may not be applicable to other periods.

Risk	EaR
(% of forecast 12 month forward earnings)	
Foreign Exchange	0.3%
Interest Rate	0.1%
Commodity	2.4%
Total Earnings at Risk	2.8%

Foreign Exchange Risk

The Company s earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from the performance of its United States dollar denominated subsidiaries. The Company has implemented a policy where it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company currently has economically hedged over 60% of its forecast adjusted earnings through 2015 at an average rate of approximately $1.20 C$/US$. The Company may also use foreign exchange forward contracts to hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt obligations. Floating to fixed interest rate swaps and options are used to hedge against the effect of future period interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility to variable rate interest expense through 2014 at an average rate of 2.1% .

The Company s earnings and cash flows are also exposed to variability in longer term interest rates on future fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2014. A total of $2,000 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.4% . Further, many of the Company s existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets, as well as through the activities of its energy services subsidiaries. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements.

The Company has implemented a hedging program to partially mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership in the Aux Sable natural gas processing plant through 2011.

CREDIT RISK

The Company s earnings and cash flows could be exposed to the risk of payment default by its shippers or other counterparties. Given the Company s desire to maintain a stable and consistent earnings profile, it has implemented a Counterparty Credit Risk Policy outlining a governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arise from counterparty defaults across any of its businesses.

Further initiatives to mitigate credit exposure include ensuring that all counterparties shipping on the regulated oil pipelines that have credit ratings below investment grade provide the carrier with a form of credit assurance, for example, a creditworthy parental guarantee, letter of credit or cash.

Credit risk in the Gas Distribution segment is mitigated by its large and diversified customer base and its ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due.

The Company minimizes credit risk to derivatives counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company s credit criteria to provide collateral. During 2009 and 2010, despite challenging market conditions, the Company did not suffer any material credit losses.

FINANCING RISK

The Company s financing risk relates to the price volatility and availability of debt to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and United States financial market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian and United States public capital markets by maintaining current shelf prospectuses with the securities regulators.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as medium-term notes. The Company maintains current shelf prospectuses with the securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL INSTRUMENTS

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its derivative instruments based on the valuations at the balance sheet date.

	2011	2012	2013	2014	2015	Thereafter
(millions of Canadian dollars)						
Cash inflows	256	136	151	152	59	43
Cash outflows	(224)	(50)	(45)	(25)	(4)	(52)
Net cash flows	32	86	106	127	55	(9)

The maturity profile of non-derivative financial liabilities is presented in *Liquidity and Capital Resources.*

FINANCIAL INSTRUMENTS

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value1
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**242**							**242**	**242**

Accounts receivable and other	**145**		**2,113**			**25**	**423**	**2,706**	**2,283**
Long-term investments		**54**	**339**	**181**			**1,624**	**2,198**	**520**
Deferred amounts and other assets	**277**		**334**			**185**	**2,090**	**2,886**	**462**
Liabilities									
Short-term borrowings					**326**			**326**	**326**
Accounts payable and other	**62**				**2,393**	**76**	**157**	**2,688**	**2,531**
Interest payable					**117**			**117**	**117**
Long-term debt					**13,715**			**13,715**	**14,770**
Non-recourse long-term debt					**1,131**			**1,131**	**1,298**
Other long-term liabilities	**6**					**127**	**1,340**	**1,473**	**133**

December 31, 2009 *(millions of Canadian dollars)*	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value[1]
Assets									
Cash and cash equivalents	327							327	327
Accounts receivable and other	76		2,054			52	302	2,484	2,182
Long-term investments		54	6	181			2,071	2,312	187
Deferred amounts and other assets	288					197	1,940	2,425	485
Liabilities									
Short-term borrowings					508			508	508
Accounts payable and other	36				2,237	87	103	2,463	2,360
Interest payable					104			104	104
Long-term debt					12,467			12,467	13,773
Non-recourse long-term debt					1,221			1,221	1,250
Other long-term liabilities	2					40	1,165	1,207	42

1 *Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market, and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.*

Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company s best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company s long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating interest rates. The fair value of the Company s long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

DERIVATIVE INSTRUMENTS

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

[redacted]

[redacted]	2011	2020	1,185	[redacted]
[redacted]	2011	2020	3,516	[redacted]
[redacted]	2011	2029	10,772	[redacted]
[redacted]	2011	2013	41	[redacted]
[redacted]	2011	2024	2	[redacted]

The Company has also designated a US$300 million (2009 US$300 million) medium-term note and US$15 million of commercial paper as hedges of certain United States dollar investments.

The following tables summarize the fair value of the Company s derivative instruments.

[redacted]

[redacted]				
[redacted]	4	15	111	130
[redacted]	6			6
[redacted]			33	33
[redacted]			1	1
[redacted]	10	15	145	170
[redacted]				
[redacted]	18	100	275	393
[redacted]	67			67
[redacted]			2	2
[redacted]	85	100	277	462
[redacted]				
[redacted]	(4)		(11)	(15)
[redacted]	(72)			(72)
[redacted]			(51)	(51)
[redacted]	(76)		(62)	(138)
[redacted]				
[redacted]	(47)		(3)	(50)
[redacted]	(80)			(80)
[redacted]			(3)	(3)
[redacted]	(127)		(6)	(133)
[redacted]				
[redacted]	(29)	115	372	458
[redacted]	(79)			(79)
[redacted]			(19)	(19)
[redacted]			1	1

[redacted]	**(108)**	**115**	**354**	**361**

[redacted]

	4	14	52	70
	34		2	36
			22	22
	38	14	76	128
	25	80	285	390
	90			90
	1		2	3
	1		1	2
	117	80	288	485
	(2)		(3)	(5)
	(68)			(68)
	(17)		(33)	(50)
	(87)		(36)	(123)
	(21)			(21)
	(15)			(15)
	(4)		(2)	(6)
	(40)		(2)	(42)
	6	94	334	434
	41		2	43
	(20)		(11)	(31)
	1		1	2
	28	94	326	448

The fair value of derivative instruments has primarily been estimated using models or other industry standard valuation techniques derived from observable market information. This market information includes published market prices for commodities, interest rate yield curves, foreign exchange rates and equity prices. When possible, financial instruments are valued using quoted market prices.

An unrealized fair value loss of $82 million (2009 $53 million) related to derivative instruments used as cash flow and net investment hedges was recognized in OCI for the year ended December 31, 2010. An unrealized fair value gain related to non-qualifying derivative instrument of $26 million (2009 $146 million gain) was recognized in commodity costs, other investment income and interest expense for the year ended December 31, 2010.

Additional information about the Company s Risk Management and Financial Instruments is included in Notes 23 and 24 of the 2010 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Execution Risk

The Company s ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, shortages and in-service delays (collectively, Execution Risk). The Company s growth plans may strain its resources and may be subject to high cost pressures in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation, and environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages may impact project development. Labour shortages, inexperience and productivity issues may also affect the successful completion of the projects.

The Company has a centralized and clearly defined governance structure and process for all major projects with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. The Company s emphasis on corporate social responsibility promotes generally positive relationships with landowners, aboriginal groups and governments which help to facilitate right-of-way acquisition, permitting and schedule. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel.

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company s pipelines or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required and are supported by operating and capital budgets directed to pipeline integrity. Emergency response plans, operator training and landowner education programs are included in the Company s response preparedness. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company feels the level of insurance is adequate, it may not be sufficient to cover all potential losses.

Regulation

Many of the Company s pipeline operations are regulated and are subject to regulatory risk. The nature anddegree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers. Recently shippers have challenged toll increases on various pipelines owned by Enbridge and some of Enbridge s competitors. Enbridge retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

Environmental, Health and Safety Risk

The Company s operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company s facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing GHG emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company s services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company s upstream customers ability to produce crude oil and natural gas. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to GHG emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Aboriginal Relations

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

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

Special Interest Groups

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on government and regulators by special interest groups. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. The Company works proactively with special interest groups to identify and develop an appropriate response to concerns regarding its projects. The Company s Corporate Social Responsibility (CSR) program also reports on the Company s responsiveness to environmental and community issues. Please see Enbridge s annual CSR report, available online at http://csr.enbridge.com/csr2010/ for further details regarding the CSR program.

Legislation Risk

Climate Change Legislation

The Canadian Federal Government has indicated that Canada will target a 17% reduction of GHG emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada s electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada s GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations are expected to be compatible with those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. Enbridge continues to monitor developments.

Renewable Energy

Enbridge has significant interests in wind, solar and geothermal power generation and is well positioned to expand this portfolio. Many programs to encourage and advance renewable energy exist in Canada and the United States as well as individual provinces and states. Enbridge continues to assess and advance renewable energy opportunities and monitor potential changes to government policies and incentives that may positively or negatively impact existing or future renewable energy projects.

Reputation Risk

The Company s reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company s business, operations or financial condition resulting from changes in the Company s reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action, increased regulatory oversight and costs.

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

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company s Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company s commitment to Green Energy).

Workforce Development

A lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human resources is balanced between hiring full-time employees and expanding the contractor workforce, particularly in the Major Projects department.

Terrorism

The risk of terrorism continues to be monitored due to the high profile of the petroleum industry in Canada and the reliance of the United States on Canadian exports. An act of terrorism may result in the loss of upstream supplies, pipelines, distribution or storage controls systems with safety and environmental implications. The Company manages this risk through comprehensive security risk mitigation strategies developed as a result of threat/vulnerability assessments and application of Canadian and United States Critical Infrastructure Agency and industry security guidelines as directed by the Enbridge Enterprise Security Management Program.

Critical Accounting Estimates

DEPRECIATION

Depreciation of property, plant and equipment, the Company s largest asset with a net book value at December 31, 2010 of $20,332 million, or 68% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company s assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company s pipelines as well as the demand for crude oil and natural gas and the integrity of the Company s systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company s business segments. For certain rate regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company s businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the ERCB and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2010, the Company s significant regulatory assets totaled $1,390 million (2009 $1,358 million) and significant regulatory liabilities totaled $1,031 million (2009 $997 million). To the extent that the regulator s actions differ from the Company s expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company s actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The Company remains able to pay the current benefit obligations using cash from operations, reflecting strong capital market performance recovery. The excess from expected return on plan assets was $47 million for the year ended December 31, 2010 (2009 $24 million shortfall) as disclosed in Note 27 to the 2010 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2010 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

[redacted]

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company s subsidiaries and investments, including EGD and EECI, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 31 of the 2010 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin setting aside funds for abandonment no later than 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 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 the scope of the asset retirements.

Change in Accounting Policies

FUTURE ACCOUNTING POLICIES

International Financial Reporting Standards (IFRS)

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

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 Canadian Accounting Standards Board (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, will continue to closely monitor developments of the IASB, and will determine whether IFRS or U.S. GAAP would provide the most useful and reliable presentation of its financial results for 2012 and future periods.

Business Combinations

The CICA issued Handbook Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company s accounting treatment of future business combinations occurring on or after January 1, 2011.

Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company s consolidated financial statements. The revised standards are effective January 1, 2011.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As of the year ended December 31, 2010, an evaluation was carried out under the supervision of and with the participation of Enbridge s management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

Management s Report on Internal Controls over Financial Reporting

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

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

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

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

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2010, based on the framework established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2010.

During the year ended December 31, 2010, there has been no change in the Company s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Non-GAAP Reconciliations

	2010	
[redacted]	963	[redacted]
[redacted]	12	[redacted]
[redacted]	(2)	[redacted]
[redacted]	(7)	[redacted]
[redacted]	12	[redacted]
[redacted]	(1)	[redacted]
[redacted]	106	[redacted]
[redacted]	1	[redacted]
[redacted]	(1)	[redacted]
[redacted]	(36)	[redacted]
[redacted]	2	[redacted]
[redacted]	(25)	[redacted]
[redacted]	(40)	[redacted]
[redacted]	984	[redacted]

MANAGEMENT S REPORT

To the Shareholders of Enbridge Inc.

FINANCIAL REPORTING

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management s judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company s internal control over financial reporting as at December 31, 2010, based on the framework established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2010.

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

Patrick D. Daniel	**J. Richard Bird**
President & Chief Executive Officer	Executive Vice President & Chief Financial Officer

February 18, 2011

INDEPENDENT AUDITOR S REPORT

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc. s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings, comprehensive income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

MANAGEMENT S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

AUDITOR S RESPONSIBILITY

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

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

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

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the three years in the period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Enbridge Inc. s internal control over financial reporting as at December 31, 2010, based on the criteria established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

MANAGEMENT S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

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

AUDITOR S RESPONSIBILITY

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

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

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

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

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

INHERENT LIMITATIONS

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

OPINION

In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control   Integrated Framework, issued by COSO.

Chartered Accountants

Calgary, Alberta, Canada

February 18, 2011

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**11,990**	9,720	13,432
Transportation and other services	**3,137**	2,746	2,699
	15,127	12,466	16,131
Expenses			
Commodity costs	**11,291**	9,011	12,792
Operating and administrative	**1,466**	1,430	1,312
Depreciation and amortization	**864**	764	658
	13,621	11,205	14,762
	1,506	1,261	1,369
Income from Equity Investments	**38**	198	177
Other Income *(Note 28)*	**374**	678	198
Interest Expense *(Note 16)*	**(687)**	(597)	(551)
Gain on Sale of Investments *(Note 6)*		365	700
	1,231	1,905	1,893
Non-Controlling Interests	**(10)**	(37)	(56)
	1,221	1,868	1,837
Income Taxes *(Note 26)*	**(251)**	(306)	(509)
Earnings	**970**	1,562	1,328
Preferred Share Dividends	**(7)**	(7)	(7)
Earnings Applicable to Common Shareholders	**963**	1,555	1,321
Earnings per Common Share *(Note 20)*	**2.60**	4.27	3.67
Diluted Earnings per Common Share *(Note 20)*	**2.57**	4.25	3.64

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings	**970**	1,562	1,328
Other Comprehensive Income/(Loss)			
Change in unrealized loss on cash flow hedges, net of tax	**(113)**	(54)	(127)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**51**	151	(160)
Reclassification to earnings of realized cash flow hedges, net of tax	**(25)**	114	(1)
Reclassification to earnings of unrealized cash flow hedges, (net of tax) *(Note 6)*		(20)	
Other comprehensive income/(loss) from equity investees, net of tax	**(11)**	(24)	49
Non-controlling interests in other comprehensive income/(loss)	**33**	72	(101)
Change in foreign currency translation adjustment	**(274)**	(815)	658
Other Comprehensive Income/(Loss)	**(339)**	(576)	318
Comprehensive Income	**631**	986	1,646

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars, except per share amounts)			
Preferred Shares *(Note 20)*	**125**	125	125
Common Shares *(Note 20)*			
Balance at beginning of year	**3,379**	3,194	3,027
Common shares issued		4	
Dividend reinvestment and share purchase plan	**224**	143	131
Shares issued on exercise of stock options	**80**	38	36
Balance at End of Year	**3,683**	3,379	3,194
Contributed Surplus			
Balance at beginning of year	**54**	38	26
Stock-based compensation	**13**	19	14
Options exercised	**(8)**	(3)	(2)
Balance at End of Year	**59**	54	38
Retained Earnings			
Balance at beginning of year	**4,400**	3,383	2,537
Earnings applicable to common shareholders	**963**	1,555	1,321
Common share dividends declared	**(648)**	(555)	(489)
Dividends paid to reciprocal shareholder	**19**	17	14
Balance at End of Year	**4,734**	4,400	3,383
Accumulated Other Comprehensive Income/(Loss) *(Note 22)*			
Balance at beginning of year	**(543)**	33	(285)
Other comprehensive income/(loss)	**(339)**	(576)	318
Balance at End of Year	**(882)**	(543)	33
Reciprocal Shareholding *(Note 11)*	**(154)**	(154)	(154)
Total Shareholders Equity	**7,565**	7,261	6,619
Dividends Paid per Common Share	**1.70**	1.48	1.32

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	[redacted]		2008
(millions of Canadian dollars)			
Operating Activities			
Earnings	**970**	1,562	1,328
Depreciation and amortization	**864**	764	658
Unrealized gains on derivative instruments	**(10)**	(204)	(120)
Allowance for equity funds used during construction	**(80)**	(135)	(59)
Cash distributions in excess of/(less than) equity earnings	**214**	(9)	(82)
Gain on reduction of ownership interest	**(81)**		(12)
Gain on sale of investments *(Note 6)*		(365)	(700)
Future income taxes	**238**	218	258
Goodwill and asset impairment losses		11	23
Non-controlling interests	**10**	37	56
Other	**(11)**	(105)	48
Changes in operating assets and liabilities *(Note 29)*	**(263)**	243	(26)
	1,851	2,017	1,372
Investing Activities			
Additions to property, plant and equipment	**(2,357)**	(3,225)	(3,545)
Additions to intangible assets	**(50)**	(95)	(91)
Change in construction payable	**27**	(110)	106
Long-term investments	**(121)**	(359)	(659)
Affiliate loans, net	**(80)**	(145)	
Acquisitions *(Notes 10 and 19)*	**(116)**		
Proceeds on sale of investments *(Note 6)*	**23**	535	1,383
Sale of property, plant and equipment		87	
Settlement of hedges *(Note 6)*		6	(47)
	(2,674)	(3,306)	(2,853)
Financing Activities			
Net change in short-term borrowings	**(182)**	(366)	329
Net change in commercial paper and credit facility draws	**(347)**	736	744
Debenture and term note issues	**2,300**	1,500	498
Debenture and term note repayments	**(600)**	(616)	(602)
Net change in Southern Lights project financing	**14**	343	1,238
Non-recourse debt issues	**5**	60	46
Non-recourse debt repayments	**(73)**	(130)	(66)
Distributions to non-controlling interests, net	**(1)**	(33)	(10)
Common shares issued	**66**	36	29
Preferred share dividends	**(7)**	(7)	(7)
Common share dividends	**(426)**	(414)	(359)
	749	1,109	1,840
Effect of translation of foreign denominated cash and cash equivalents	**(11)**	(35)	16
Increase/(Decrease) in Cash and Cash Equivalents	**(85)**	(215)	375
Cash and Cash Equivalents at Beginning of Year	**327**	542	167
Cash and Cash Equivalents at End of Year 1	**242**	327	542
Supplementary Cash Flow Information			
Income taxes paid *(Note 26)*	**108**	205	161
Interest paid *(Note 16)*	**711**	656	607

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

1 Cash and cash equivalents consists of $143 million (2009 $184 million; 2008 $68 million) of cash and $99 million (2009 $143 million; 2008 $474 million) of short-term investments and includes restricted cash of $12 million (2009 $7 million; 2008 $24 million), and joint-venture cash which is not readily accessible by the Company of $48 million (2009 $52 million; 2008 $57 million).

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31, *(millions of Canadian dollars)*	**2010**	2009
Assets		
Current Assets		
Cash and cash equivalents	**242**	327
Accounts receivable and other *(Note 7)*	**2,706**	2,484
Inventory *(Note 8)*	**813**	784
	3,761	3,595
Property, Plant and Equipment, net *(Note 9)*	**20,332**	18,850
Long-Term Investments *(Note 11)*	**2,198**	2,312
Deferred Amounts and Other Assets *(Note 12)*	**2,886**	2,425
Intangible Assets *(Note 13)*	**478**	488
Goodwill *(Note 14)*	**385**	372
Future Income Taxes *(Note 26)*	**80**	127
	30,120	28,169
Liabilities and Shareholders Equity		
Current Liabilities		
Short-term borrowings *(Note 16)*	**326**	508
Accounts payable and other *(Note 15)*	**2,688**	2,463
Interest payable	**117**	104
Current maturities of long-term debt *(Note 16)*	**154**	601
Current maturities of non-recourse long-term debt *(Note 17)*	**70**	113
	3,355	3,789
Long-Term Debt *(Note 16)*	**13,561**	11,866
Non-Recourse Long-Term Debt *(Note 17)*	**1,061**	1,108
Other Long-Term Liabilities *(Note 18)*	**1,473**	1,207
Future Income Taxes *(Note 26)*	**2,447**	2,211
	21,897	20,181
Non-Controlling Interests *(Note 19)*	**658**	727
Shareholders Equity		
Share capital		
Preferred shares *(Note 20)*	**125**	125
Common shares *(Note 20)*	**3,683**	3,379
Contributed surplus	**59**	54
Retained earnings	**4,734**	4,400
Accumulated other comprehensive loss *(Note 22)*	**(882)**	(543)
Reciprocal shareholding *(Note 11)*	**(154)**	(154)
	7,565	7,261
Commitments and Contingencies *(Note 31)*		
	30,120	28,169

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

Approved by the Board of Directors:

David A. Arledge
Chair

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. General Business Description

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments, and Corporate. These operating segments have been revised to better reflect the strategic business units established by senior management to facilitate the achievement of the Company s long-term objectives, to aid in resource allocation decisions and to assess operational performance. Segmented information has been retroactively reclassified to reflect these changes, but had no impact on reported Consolidated Earnings Applicable to Common Shareholders.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States, including the Enbridge System, the Enbridge Regional Oil Sands System, Southern Lights Pipeline and other feeder pipelines.

GAS DISTRIBUTION

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, processing and green energy projects, the Company s commodity marketing businesses and international activities.

Investments in natural gas pipelines include the Company s interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in processing includes the Company s interest in Aux Sable, a natural gas fractionation and extraction business. The commodity marketing businesses manage the Company s volume commitments on Alliance and Vector Pipelines, as well as perform commodity storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company s 25.5% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge s 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, L.P. (EELP) and an overall 72% economic interest in Enbridge Income Fund (EIF), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (EIFH). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of EIF include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline Canada and partial interests in several green energy investments.

CORPORATE

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

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). 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 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post employment benefits *(Note 27)*; commitments and contingencies *(Note 31)*; and fair value of asset retirement obligations. Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of various joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through the combination of a total direct and indirect 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to Maturity, Loans and Receivables or Available for Sale (see Financial Instruments).

REGULATION

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

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are included in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

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

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration.

For the rate-regulated portion of the Company s main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For rate-regulated operations in Sponsored Investments and in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the consolidated statement of financial position. Subsequent measurement of the financial instrument is based on its classification.

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Commodity Costs, Other Income and Interest Expense. The Company has classified Cash and Cash Equivalents and its non-qualifying derivative instruments as held for trading.

Available for Sale

Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other Comprehensive Income/(Loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from Available for Sale financial assets are recognized in earnings when the right to receive payment is established.

Loans and Receivables

Loans and receivables, which include Accounts Receivable and Other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Held to Maturity

The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

Other Financial Liabilities

Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term Borrowings, Accounts Payable and Other, Interest Payable, Long-term Debt and Non-recourse Long-term Debt.

Derivatives in Qualifying Hedging Relationships

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

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

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

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

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

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statement of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Impairment

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

With respect to loans and receivables, the Company assesses the assets for impairment when it no longer has a reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the loan or receivable to its estimated realizable amount, determined using discounted expected future cash flows.

Transaction Costs

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

INCOME TAXES

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company s regulated operations, a future income tax liability is recognized with a corresponding regulatory asset.

FOREIGN CURRENCY TRANSLATION

The Company s foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these operations are included in the foreign currency translation adjustment component of AOCI.

Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statement of Earnings in the period that they arise.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate-regulated assets, if approved, an allowance for equity funds used during construction (AEDC) is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

IMPAIRMENT OF LONG-LIVED ASSETS

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

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts and software costs, which are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit s allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

ASSET RETIREMENT OBLIGATIONS

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

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

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management s best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

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

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

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

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

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

STOCK BASED COMPENSATION

Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units (RSUs) vest at the completion of a 35-month term. Both PSUs and RSUs are settled in cash. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company s shares with an offset to Accounts Payable and Other or Other Long-Term Liabilities. The value of the PSUs is also dependent on the Company s performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year s financial statement presentation.

3. Changes in Accounting Policies

FUTURE ACCOUNTING POLICY CHANGES

International Financial Reporting Standards

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

Business Combinations

CICA Handbook Section 1582, *Business Combinations* replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company s accounting treatment of future business combinations occurring on or after January 1, 2011.

Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards impacts presentation only. They are not expected to have a material impact to the Company s consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

4. Segmented Information

Year ended December 31, 2010	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
[redacted]	**1,672**	**2,611**	**10,518**	**326**		**15,127**
		(1,384)	**(9,907)**			**(11,291)**
	(603)	**(497)**	**(215)**	**(120)**	**(31)**	**(1,466)**
	(312)	**(310)**	**(144)**	**(88)**	**(10)**	**(864)**

[redacted]	757	420	252	118	(41)	1,506
				32	6	38
	115	(17)	30	114	132	374
	(223)	(179)	(96)	(58)	(138)	(694)
	(2)	(5)		(3)		(10)
	(135)	(64)	(65)	(66)	79	(251)
	512	155	121	137	38	963

Year ended December 31, 2009	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
[redacted]						

Year ended December 31, 2008	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
[redacted]						

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

TOTAL ASSETS

December 31,	[redacted]	2009
(millions of Canadian dollars)		
Liquids Pipelines	**11,503**	10,763
Gas Distribution	**7,562**	7,377
Gas Pipelines, Processing and Energy Services	**5,533**	4,801
Sponsored Investments	**3,822**	3,860
Corporate	**1,700**	1,368
	30,120	28,169

ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT 1

December 31,	[redacted]	2009
[redacted]	765	[redacted]
[redacted]	387	[redacted]
[redacted]	1,153	[redacted]
[redacted]	132	[redacted]
[redacted]	2,437	[redacted]

1 Includes AEDC.

GEOGRAPHIC INFORMATION

Revenues 1

Year ended December 31,	[redacted]	2009	2008
[redacted]	9,876	[redacted]	[redacted]
[redacted]	5,251	[redacted]	[redacted]
[redacted]	15,127	[redacted]	[redacted]

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

Property, Plant and Equipment

December 31,	2010	2009
[redacted]	16,095	[redacted]
[redacted]	4,237	[redacted]
	20,332	18,850

5. Financial Statement Effects of Rate Regulation

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company s significant regulated businesses and related accounting impacts are described below.

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are based on a cost of service methodology and are based on agreements with customers which are filed with the NEB for approval.

The incentive tolling settlement (ITS) was effective from 2005 to 2009 and a one year ITS was approved by the NEB for 2010. The Company has reached agreement with industry to roll forward the 2010 ITS agreement for a year and will file the 2011 ITS with the NEB in March 2011. The ITS defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval. Surcharges are also determined for a number of system expansion components and are added to the base toll determined for the core system. Discussions with industry continue for a longer term settlement agreement which will support a competitive toll structure. Until all matters before the NEB are settled, interim tolls will continue to be collected for the Enbridge System.

Southern Lights

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD s gas distribution operations are regulated by the OEB. EGD s rates are based on a revenue per customer cap incentive regulation (IR) methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD s after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2010, 2009 and 2008 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB s after-tax ROE for the year ended December 31, 2010 was 13.00% (2009 13.00%; 2008 13.00%) based on equity which is capped at 50%.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2010 included an after tax ROE component of 11.18% (2009 11.07%; 2008 11.04%).

Alliance Pipeline

The United States portion of the Alliance Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Alliance Pipeline are subject to 15-year transportation contracts that expire in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2010, 2009 and 2008 included an after tax ROE component of 10.88% for the United States portion and 11.26% for the Canadian portion. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

FINANCIAL STATEMENT EFFECTS

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

			Estimated Settlement	Earnings Impact 1		
December 31,	**2010**	2009	Period *(years)*	**2010**	2009	2008
Regulatory Assets/(Liabilities)		[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	**575**	[redacted]		**53**	[redacted]	[redacted]
[redacted]	**91**	[redacted]	1	**(7)**	[redacted]	[redacted]
[redacted]	**169**	[redacted]		**(7)**	[redacted]	[redacted]
[redacted]	**171**	[redacted]	[redacted]	**18**	[redacted]	[redacted]
[redacted]	**(773)**	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	**(144)**	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	**(114)**	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	**42**	[redacted]	[redacted]	**(5)**	[redacted]	[redacted]
[redacted]	**150**	[redacted]	[redacted]	**(17)**	[redacted]	[redacted]
[redacted]	**94**	[redacted]	[redacted]	**(3)**	[redacted]	[redacted]
[redacted]	**98**	[redacted]	[redacted]	**5**	[redacted]	[redacted]

1 The effect of a number of the Company s businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.

2 This regulatory asset is a corresponding balance to a future income tax liability, first recognized on adoption of the revised CICA Handbook section 3465 Income Taxes in 2009. The asset represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.

3 Tolls are calculated in accordance with the ITS, System Expansion Program (SEP), Terrace, Southern Access, Line 4, Alberta Clipper and Southern Lights Pipeline agreements and are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a regulatory asset is recognized and incorporated into tolls in the subsequent year. Recovery in the subsequent year, in whole or in part, is dependent upon realizing shipping volumes consistent with tolling model forecasts. Under or over collections are included in subsequent years tolls. In addition, other tolling deferrals are recorded in accordance with the various agreements.

4 A regulatory deferral account captures the cumulative difference between EGNB s distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end in 2043.

5 The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company s businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

6 Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity sales would be adjusted by an equal and corresponding amount as the right to collect revenue has been established.

7 The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The other post employment benefits (OPEB) balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.

8 Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

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

Operating Cost Capitalization

With the approval of the OEB, EGD capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2010, cumulative costs relating to this consulting contract of $124 million (2009 $112 million) were included in property plant and equipment, and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. Gain on Sale of Investments

NTP

On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million (2008 $1 million) and are included in the Corporate operating segment.

OCENSA

On March 17, 2009, the Company sold its investment in 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 year ended December 31, 2009 were $7 million (2008 $33 million). Earnings from the OCENSA investment are included in the Gas Pipelines, Processing and Energy 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 OCI to earnings in the year ended December 31, 2009.

CLH

On June 17, 2008, the Company sold its 25% investment in CLH for total proceeds of $1,380 million (876 million), net of transaction costs. The sale of CLH resulted in a gain of $695 million. Earnings generated by the CLH investment for the year ended December 31, 2008 were $25 million and are included in the Gas Pipelines, Processing and Energy Services operating segment. Operating cash flows generated by the CLH investment for the year ended December 31, 2008 were $12 million.

7. Accounts Receivable and Other

December 31, *(millions of Canadian dollars)*	**2010**	2009
[redacted]	**1,284**	[redacted]
[redacted]	**740**	[redacted]
[redacted]	**205**	[redacted]
[redacted]	**182**	[redacted]
[redacted]	**170**	[redacted]
[redacted]	**63**	[redacted]
[redacted]	**36**	[redacted]
[redacted]	**16**	[redacted]
[redacted]	**72**	[redacted]
[redacted]	**(62)**	[redacted]
[redacted]	**2,706**	[redacted]

8. Inventory

December 31, *(millions of Canadian dollars)*	**2010**	2009
[redacted]	**537**	[redacted]
[redacted]	**276**	[redacted]
[redacted]	**813**	[redacted]

9. Property, Plant and Equipment

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.7%	**7,295**	**1,618**	**5,677**
Pumping equipment, buildings, tanks and other	3.6%	**4,728**	**1,221**	**3,507**
Land and right-of-way	1.8%	**232**	**29**	**203**
Under construction		**728**		**728**
		12,983	**2,868**	**10,115**
Gas Distribution				
Pipeline	2.3%	**29**	**10**	**19**
Gas mains, services and other	3.6%	**6,576**	**1,262**	**5,314**
Land and right-of-way	2.6%	**68**	**15**	**53**
Under construction		**103**		**103**
		6,776	**1,287**	**5,489**
Gas Pipelines, Processing and Energy Services				
Pipeline	3.4%	**2,121**	**706**	**1,415**
Wind turbines, solar panels and other	3.1%	**1,527**	**142**	**1,385**
Land and right-of-way	2.4%	**62**	**13**	**49**
Under construction		**622**		**622**
		4,332	**861**	**3,471**
Sponsored Investments				
Pipeline	4.0%	**1,598**	**484**	**1,114**
Other	8.5%	**108**	**29**	**79**
Under construction		**17**		**17**
		1,723	**513**	**1,210**
Corporate				
Other	11.3%	**67**	**20**	**47**
		67	**20**	**47**
		25,881	**5,549**	**20,332**

December 31, 2009	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.4%	4,053	1,481	2,572
Pumping equipment, buildings, tanks and other	3.5%	4,029	1,065	2,964
Land and right-of-way	2.0%	118	23	95
Under construction		4,129		4,129
		12,329	2,569	9,760
Gas Distribution				
Pipeline	2.3%	21	5	16
Gas mains, services and other	3.8%	6,122	982	5,140
Land and right-of-way	5.0%	49	8	41
Under construction		111		111
		6,303	995	5,308
Gas Pipelines, Processing and Energy Services				
Pipeline	3.4%	2,104	679	1,425
Wind turbines, solar panels and other	3.8%	890	108	782
Land and right-of-way	2.9%	48	13	35
Under construction		321		321
		3,363	800	2,563
Sponsored Investments				
Pipeline	4.6%	1,406	368	1,038
Other	6.9%	108	18	90
Under construction		31		31
		1,545	386	1,159
Corporate				
Other	11.3%	77	17	60
		77	17	60
		23,617	4,767	18,850

10. Joint Ventures

The impact of the Company s joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

		Net Assets	
December 31,	Ownership Interest	**2010**	2009
(millions of Canadian dollars)			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	9
Mustang Pipeline	30%	**26**	22
Olympic Pipeline	85% (2009 65%)		111
Hardisty Caverns	100% (2009 50%)		33
Gas Pipelines, Processing and Energy Services			
Enbridge Offshore Pipelines various joint ventures	22% 74.3%	**433**	385
Vector Pipeline	60%	**349**	420
Alliance Pipeline US	50%	**318**	383
Aux Sable	42.7% 50%	**86**	153
Other	33.3% 70%	**50**	32
Sponsored Investments			
Alliance Pipeline Canada	50%	**660**	676
Other	33% 50%	**56**	46
		2,005	2,270

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company:

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings			
Revenues	**771**	781	891
Commodity costs	**(92)**	(74)	(174)
Operating and administrative	**(203)**	(226)	(235)
Depreciation and amortization	**(163)**	(171)	(173)
Interest expense	**(82)**	(99)	(97)
Other income/(expense)	**(1)**	10	13
Proportionate share of earnings	**230**	221	225
Cash Flows			
Cash provided by operating activities	**349**	342	408
Cash used in investing activities	**(57)**	(49)	(61)
Cash used in financing activities	**(78)**	(133)	(121)
Proportionate share of increase in cash and cash equivalents	**214**	160	226

December 31,	**2010**	2009
(millions of Canadian dollars)		
Financial Position		
Current assets	**171**	173
Property, plant and equipment, net	**2,331**	2,657
Intangible assets	**166**	188
Goodwill	**321**	321
Deferred amounts and other assets	**270**	299
Current liabilities	**(150)**	(212)
Non-recourse long-term debt	**(1,061)**	(1,108)
Other long-term liabilities	**(43)**	(48)
Proportionate share of net assets	**2,005**	2,270

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipeline Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

During the year ended December 31, 2008, the Company purchased an additional equity interest in Chicap Pipeline Company (Chicap Pipeline), increasing its ownership percentage to 43.8%. As the Company established joint control over the entity effective October 31, 2008, it has proportionally consolidated its interest in Chicap Pipeline from that date forward. Prior to October 31, 2008, the entity was classified as a long-term investment.

11. Long-Term Investments

December 31,	Ownership Interest	**2010**	2009
(millions of Canadian dollars)			
Equity Investments			
Sponsored Investments			
The Partnership	25.5%	**1,473**	1,697
Enbridge Energy, L.P. Series AC	66.7%	**463**	357
Corporate			
Noverco Inc. Common Shares	32.1%	**14**	14
Other	5% 14%	**13**	9
Other Investments			
Corporate			
Noverco Inc. Preferred Shares		**181**	181
Value Creation Inc.		**29**	29
Fuel Cell Energy Ltd.		**25**	25
		2,198	2,312

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee s assets at the purchase date of $123 million at December 31, 2010 (2009 $126 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

THE PARTNERSHIP

The Partnership includes the Company s investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 25.5% ownership in EEP, through a 2.0% general partner interest, an 18.1% interest in Class A units, a 3.0% interest in Class B units and a 2.4% interest in EEP as a result of a 17.2% investment in EEM, which owns 13.7% of EEP through its 100% interest in EEP s i-units. The Company recorded investment income of $51 million (2009 $175 million; 2008 $162 million), inclusive of incentive earnings, and including dilution gains of $81 million (2009 nil; 2008 $12 million), before tax and non-controlling interest, from EEP for the year ended December 31, 2010.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million, before tax and non-controlling interest, was recognized and Enbridge s ownership interest in EEP decreased from 27.0% to 25.5%.

Although 82.8% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

In October 2009, the Company converted its investment in EEP Class C units into Class A common units. The Class C units converted on a one-for-one basis, resulting in the issuance and receipt of 21,333,273 Class A common units. Prior to the unit conversion, distributions were paid in additional Class C units where Class C units were valued at the market value of Class A units.

In March 2008, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $12 million, before tax and non-controlling interest, was recognized and Enbridge s ownership interest in EEP decreased from 15.1% to 14.6%. In November 2008, the Company subscribed for 16.3 million Class A common units of EEP for US$510 million increasing its ownership interest from 14.6% to 27.0%.

ENBRIDGE ENERGY, L.P.

The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project *(Note 30)*. The Company recorded investment income from EELP of $63 million for the year ended December 31, 2010 (2009 $12 million).

During 2010, the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $40 million (US$39 million) payable to the Company relating to its series AC interest in the Alberta Clipper project.

NOVERCO

The Company owns a preferred share investment in Noverco of $181 million at December 31, 2010 and 2009, which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%.

The Company also owns an equity investment in the common shares of Noverco of $14 million at December 31, 2010 (2009 $14 million). Noverco owns an approximate 9.0% (2009 9.2%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 2.9% (2009 2.9%) in its own shares. Both the equity investment in Noverco and shareholders equity have been reduced by the reciprocal shareholding of $154 million at December 31, 2010 and 2009. Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company s investment in Noverco. In 2010, the Company recorded equity investment earnings of $6 million (2009 $10 million; 2008 $4 million) related to its interest in Noverco.

Subsequent to December 31, 2010, the Company announced that it will invest $145 million to acquire an additional 6.8% interest in Noverco, bringing its total investment in Noverco to 38.9%.

12. Deferred Amounts and Other Assets

December 31,	**2010**	2009
(millions of Canadian dollars)		
Regulatory assets	**1,514**	1,419
Long-term portion of derivative assets *(Note 23)*	**462**	485
Affiliate long-term note receivable *(Note 30)*	**334**	
Pension asset *(Note 27)*	**301**	216
Contractual receivables	**182**	171
Other	**93**	134
	2,886	2,425

At December 31, 2010, deferred amounts of $66 million (2009 $71 million) were subject to amortization and are presented net of accumulated amortization of $39 million (2009 $34 million). Amortization expense in 2010 was $9 million (2009 $7 million; 2008 $5 million).

13. Intangible Assets

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**13.4%**	**457**	**172**	**285**
Transportation agreements	**4.2%**	**231**	**66**	**165**
Power purchase agreements and other	**5.0%**	**33**	**5**	**28**
		721	**243**	**478**

December 31, 2009	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	17.1%	448	159	289
Transportation agreements	4.2%	232	56	176
Power purchase agreements and other	5.0%	27	4	23
		707	219	488

Total amortization expense for intangible assets was $60 million for the year ended December 31, 2010 (2009 $44 million; 2008 $58 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2011 through 2015 of $47 million, $41 million, $36 million, $32 million and $28 million, respectively.

14. Goodwill

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at December 31, 2008	22		59	308		389
Goodwill impairment			(7)			(7)
Foreign exchange and other	(3)		(7)			(10)
Balance at December 31, 2009	19		45	308		372
Foreign exchange and other	**(1)**		**(3)**			**(4)**
Business acquisition	**17**					**17**
Balance at December 31, 2010	**35**		**42**	**308**		**385**

In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns. In 2009, the Company recognized an impairment of $7 million on goodwill related to Enbridge Electric Connections Inc.

15. Accounts Payable and Other

December 31,	**2010**	2009
(millions of Canadian dollars)		
Operating accrued liabilities	**1,621**	1,313
Trade payables	**232**	415
Construction payables	**253**	163
Taxes payable	**156**	103
Current derivative liabilities *(Note 23)*	**138**	123
Security deposits	**78**	60
Contractor holdbacks	**78**	108
Other	**132**	178
	2,688	2,463

16. Debt

December 31,	Weighted Average Interest Rate	Maturity		2010	2009
(millions of Canadian dollars)					
Liquids Pipelines					
Debentures	8.20%		2024	**200**	200
Medium-term notes	5.05%	2012	2040	**2,425**	1,525
Southern Lights project financing 1	2.54%	2012	2014	**1,488**	1,531
Commercial paper and credit facility draws, net 2				**36**	874
Other 3				**15**	15
Gas Distribution					
Debentures	10.46%	2011	2024	**235**	385
Medium-term notes	5.54%	2014	2050	**2,195**	1,795
Commercial paper and credit facility draws, net				**334**	512
Sponsored Investments					
Medium-term notes	5.03%	2014	2020	**290**	90
Credit facility draws, net				**130**	197
Corporate					
U.S. dollar term notes 4	5.48%	2014	2017	**1,094**	1,151
Medium-term notes	5.25%	2013	2040	**2,918**	2,568
Commercial paper and credit facility draws, net 5				**2,776**	2,235
Deferred debt issue costs and other				**(95)**	(103)
Total Debt				**14,041**	12,975
Current Maturities				**(154)**	(601)
Short-Term Borrowings	1.14%			**(326)**	(508)
Long-Term Debt				**13,561**	11,866

1 2010 $388 million and US$1,106 million (2009 $385 million and US$1,095 million).

2 2010 $26 million and US$10 million (2009 $874 million).

3 Primarily capital lease obligations.

4 2010 US$1,100 (2009 US$1,100).

5 2010 $2,515 million and US$265 million (2009 $1,973 million and US$250 million).

Debenture and term note maturities for the years ending December 31, 2011 through 2015 are $154 million, $250 million, $201 million, $889 million and $549 million, respectively. The Company s debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2011 through 2015 are $511 million, $504 million, $487 million, $466 million and $426 million, respectively.

INTEREST EXPENSE

Year ended December 31,	2010	2009	2008
(millions of Canadian dollars)			
Debentures and term notes	**578**	494	417
Non-recourse long-term debt *(Note 17)*	**75**	83	87
Commercial paper and credit facility draws	**63**	71	100

Southern Lights project financing	**37**	45	28
Capitalized	**(66)**	(96)	(81)
	687	597	551

CREDIT FACILITIES

December 31, 2010	Expiry Dates2	Total Facilities	Credit Facility Draws 3	Available
(millions of Canadian dollars)				
Liquids Pipelines	**2012**	**200**	**26**	**174**
Gas Distribution	**2011 2012**	**717**	**334**	**383**
Sponsored Investments	**2012**	**300**	**130**	**170**
Corporate	**2012 2014**	**4,631**	**2,826**	**1,805**
		5,848	**3,316**	**2,532**
Southern Lights project financing 1	**2012 2014**	**1,697**	**1,504**	**193**
Total Credit Facilities		**7,545**	**4,820**	**2,725**

1 *Total facilities inclusive of $60 million for debt service reserve letters of credit.*

2 *Includes $30 million in demand facilities with no maturity date.*

3 *Includes facility draws, letters of credit and commercial paper issuances, that are backstopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.20% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2011 to 2014.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,950 million (2009 $3,310 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. Non-Recourse Debt

December 31,	Weighted Average Interest Rate	Maturity	**2010**	2009
(millions of Canadian dollars)				
Gas Pipelines, Processing and Energy Services				
Long-term credit facilities 1		2012	**1**	1
Senior notes 2	6.79%	2015 2025	**347**	400
Term debt 3	3.81%	2011 2019	**29**	24
Capital lease obligations	11.27%	2020	**32**	36
Sponsored Investments				
Credit facilities		2012	**23**	25
Senior notes	6.68%	2015 2025	**675**	708
Fair value increment on senior notes acquired			**29**	33
Deferred debt issue costs and other			**(5)**	(6)
Total Non-Recourse Debt			**1,131**	1,221

Current Maturities	**(70)**	(113)
Non-Recourse Long-Term Debt	**1,061**	1,108

1 *2010 US$1 million (2009 US$1 million).*

2 *2010 US$349 million (2009 US$382 million).*

3 *2010 US$24 million (2009 US$23 million).*

Maturities on non-recourse borrowings for the years ending December 31, 2011 through 2015 are $70 million, $94 million, $77 million, $80 million and $80 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2011 through 2015 are $71 million, $66 million, $61 million, $56 million and $50 million, respectively.

Certain assets of Alliance Pipeline Canada, with a carrying value of $1,006 million, are pledged as collateral to Alliance Pipeline Canada s lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US, with a carrying value of $722 million, are pledged as collateral to Alliance Pipeline US s lenders and to the lenders to Alliance Pipeline Canada.

18. Other Long-Term Liabilities

December 31,	**2010**	2009
(millions of Canadian dollars)		
Future removal and site restoration reserves *(Note 5)*	**773**	710
Regulatory liabilities	**198**	138
Derivative liabilities *(Note 23)*	**133**	42
Other post-employment benefit liabilities *(Note 27)*	**118**	110
Other	**251**	207
	1,473	1,207

19. Non-Controlling Interests

December 31,	**2010**	2009
(millions of Canadian dollars)		
EEM	**394**	424
EIF	**109**	134
EGD Preferred Shares	**100**	100
EGNB		54
Talbot Windfarm, LP (Talbot)	**26**	9
Greenwich Windfarm, LP (Greenwich)	**12**	
Other	**17**	6
	658	727

Non-controlling interests in EEM represents the 82.8% of the listed shares of EEM not held by the Company. Non-controlling interests in EIF represents 58.1% of interests that are held by third parties.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2010, no preferred shares have been redeemed.

During the year ended December 31, 2010, the Company acquired the remaining 27.5% of EGNB limited partnership units held by third parties for $52 million, increasing its partnership interest to 100%.

Non-controlling interests in both Talbot and Greenwich represent 10.0% of partnership units held by a third party.

20. Share Capital

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

COMMON SHARES

	2010		2009		2008	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars, number of common shares in millions)						
Balance at beginning of year	**378**	**3,379**	373	3,194	369	3,027
Common shares issued				4		
Shares issued on exercise of stock options	**3**	**80**	1	38	1	36
Dividend Reinvestment and Share Purchase Plan	**4**	**224**	4	143	3	131
Balance at end of year	**385**	**3,683**	378	3,379	373	3,194

PREFERRED SHARES

The five million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25 per share plus all accrued and unpaid dividends.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company s pro-rata weighted average interest in its own common shares of 11 million (2009 11 million; 2008 11 million), resulting from the Company s reciprocal investment in Noverco.

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

December 31,	**2010**	2009	2008
(number of common shares in millions)			
Weighted average shares outstanding	**370**	364	360
Effect of dilutive options	**4**	2	3
Diluted weighted average shares outstanding	**374**	366	363

For the year ended December 31, 2010, 46,000 anti-dilutive stock options (2009 556,500; 2008 2,879,800) with a weighted average exercise price of $55.68 (2009 $40.98; 2008 $40.53) were excluded from the diluted earnings per share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

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

SHAREHOLDER RIGHTS PLAN

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

21. Stock Option and Stock Unit Plans

The Company maintains four long term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Based Stock Option (PBSO) Plan, the PSU Plan and the RSU Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 20 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans, of which 0.3 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2010 for ISOs is $11 million (2009 $17 million; 2008 $13 million).

Outstanding Incentive Stock Options

	2010		2009		2008	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**12,466**	**34.01**	10,650	31.05	9,237	27.24
Options granted	**2,000**	**45.40**	3,028	39.62	2,642	40.54
Options exercised	**(1,718)**	**29.04**	(1,187)	22.01	(1,178)	21.85
Options cancelled or expired	**(18)**	**24.89**	(25)	40.65	(51)	36.83
Options at end of year	**12,730**	**36.48**	12,466	34.01	10,650	31.05
Options vested	**6,882**	**32.01**	6,550	28.96	6,087	25.32

The total intrinsic value of ISOs exercised during the year ended December 31, 2010 was $38 million (2009 $22 million; 2008 $23 million) and cash received on exercise was $50 million (2009 $26 million; 2008 $26 million). Intrinsic value represents the difference between the Company s share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2010 was $182 million (2009 $81 million) and $131 million (2009 $76 million), respectively.

Incentive Stock Option Characteristics

December 31, 2010	Options Outstanding			Options Vested		
Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
15.00 19.99	**222**	**0.1**	**19.10**	**222**	**0.1**	**19.10**
20.00 24.99	**1,399**	**1.7**	**21.27**	**1,399**	**1.7**	**21.27**
25.00 29.99	**851**	**3.1**	**25.72**	**851**	**3.1**	**25.72**
30.00 34.99	**1,487**	**5.7**	**31.68**	**1,017**	**4.6**	**31.74**
35.00 39.99	**4,336**	**7.0**	**38.55**	**2,262**	**6.1**	**37.75**
40.00 44.99	**2,783**	**7.4**	**40.82**	**1,131**	**7.1**	**40.39**
45.00 49.99	**1,606**	**9.1**	**46.59**			
55.00 59.99	**46**	**9.9**	**55.68**			
	12,730	**6.2**	**36.48**	**6,882**	**4.6**	**32.01**

The total fair value of options vested under the ISO Plan during the year ended December 31, 2010 was $14 million (2009 $13 million).

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

Year ended December 31,	**2010**	2009	2008
[redacted]	**6.88**	[redacted]	[redacted]
[redacted]	**6**	[redacted]	[redacted]
[redacted]	**19.72%**	[redacted]	[redacted]
[redacted]	**3.64%**	[redacted]	[redacted]
[redacted]	**2.70%**	[redacted]	[redacted]

1 *Options granted to United States employees are based on New York Stock Exchange (NYSE) prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair values per option were $6.56 (2009 $6.73; 2008 $6.20) for Canadian employees and US$8.00 (2009 US$6.86; 2008 US$5.82) for United States employees.*

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

3 *Expected volatility is determined with reference to historic daily share price volatility and beginning in 2010, implied volatility observable in call option values near the grant date.*

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

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

As of December 31, 2010, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $16 million. The cost is expected to be fully recognized by December 31, 2013.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2010 for PBSOs was $2 million (2009 $2 million; 2008 $2 million).

Outstanding Performance Based Stock Options

December 31,	**2010**		2009		2008	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						

Options at beginning of year	**3,395**	**33.69**	3,738	32.72	3,588	31.92
Options granted					250	40.42
Options exercised	**(1,039)**	**26.24**	(343)	23.15	(100)	23.15
Options cancelled	**(209)**	**36.57**				
Options at end of year	**2,147**	**37.02**	3,395	33.69	3,738	32.72
Options vested	**1,262**	**36.88**	800	23.15	1,143	23.15

The total intrinsic value of PBSOs exercised during the year ended December 31, 2010 was $26 million (2009 $6 million; 2008 $2 million) and cash received on exercise was $27 million (2009 $8 million; 2008 $2 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2010 is $30 million (2009 $23 million) and $18 million (2009 $14 million), respectively.

Performance Based Stock Option Characteristics

December 31, 2010	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
36.57	**1,897**	**4.6**	**36.57**	**1,162**	**4.6**	**36.57**
40.42	**250**	**4.6**	**40.42**	**100**	**4.6**	**40.42**
	2,147	**4.6**	**37.02**	**1,262**	**4.6**	**36.88**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2010 was $2 million (2009 $2 million; 2008 $2 million).

Assumptions used to determine the fair value of the PBSOs at the date of grant using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2008
Fair value per option *(Canadian dollars)*	4.82
Valuation assumptions	
Expected option term *(years)* 1	8
Expected volatility 2	13.60%
Expected dividend yield 3	3.32%
Risk-free interest rate 4	3.75%

1 *Expected option term is based on historical information.*

2 *Expected volatility is determined with reference to 20-day rolling period historic share price information.*

3 *The expected dividend yield is the current annual dividend divided by the current stock price.*

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

As of December 31, 2010, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $3 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company s weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company s performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2008, 2009 and 2010 grants derive the performance multiplier through a calculation of the Company s price/earnings ratio relative to a specified peer group of companies and the Company s earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2010 for PSUs was $27 million (2009 $20 million; 2008 $13 million). To calculate the 2010 expense, multipliers of two, based upon multiplier estimates at December 31, 2010, were used for each of the 2008, 2009 and 2010 PSU grants.

Outstanding Performance Stock Units

December 31,	**2010**	2009	2008
Units at beginning of year	**330,416**	295,428	267,616
Units granted	**286,200**	169,600	144,300
Units cancelled			
Units matured	**(159,817)**	(151,882)	(129,852)
Dividend reinvestment	**21,148**	17,270	13,364
Units at end of year	**477,947**	330,416	295,428

Of the PSUs outstanding at December 31, 2010, 181,932 units have a performance period ending December 31, 2011 and 296,015 have a performance period ending December 31, 2012. The total intrinsic value of PSUs outstanding at December 31, 2010 is $56 million (2009 $47 million; 2008 $21 million).

RESTRICTED STOCK UNITS

Enbridge has a RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company s weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2010 for RSUs was $29 million (2009 $23 million; 2008 $15 million).

Outstanding Restricted Stock Units

December 31,	**2010**	2009	2008
Units at beginning of year	**987,877**	700,034	456,621
Units granted	**468,600**	543,500	418,700
Units cancelled	**(30,454)**	(18,429)	(23,352)
Units matured	**(427,752)**	(282,656)	(179,940)
Dividend reinvestment	**49,714**	45,428	28,005
Units at end of year	**1,047,985**	987,877	700,034

The total intrinsic value of RSUs outstanding at December 31, 2010 is $63 million (2009 $50 million; 2008 $29 million).

As of December 31, 2010, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $62 million and is expected to be fully recognized by December 31, 2012.

22. Components of Accumulated Other Comprehensive Income/(Loss)

	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Non-Controlling Interests	Cash Flow Hedges	Total
(millions of Canadian dollars)						
Balance at January 1, 2008	438	(933)	(57)	118	149	(285)
Changes during the year	(180)	658	78	(101)	(175)	280
Tax impact	20		(29)		47	38
	(160)	658	49	(101)	(128)	318
Balance at December 31, 2008	278	(275)	(8)	17	21	33
Changes during the year	181	(815)	(38)	72	71	(529)
Tax impact	(30)		14		(31)	(47)
	151	(815)	(24)	72	40	(576)
Balance at December 31, 2009	429	(1,090)	(32)	89	61	(543)
Changes during the year	**61**	**(274)**	**(18)**	**33**	**(133)**	**(331)**
Tax impact	**(10)**		**7**		**(5)**	**(8)**
	51	**(274)**	**(11)**	**33**	**(138)**	**(339)**
Balance at December 31, 2010	**480**	**(1,364)**	**(43)**	**122**	**(77)**	**(882)**

23. Risk Management

MARKET PRICE RISK

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

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company s policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company s Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge s current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Foreign Exchange Risk

The Company s earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2010, would have resulted in a $81 million increase (2009 $92 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company s functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company s United States dollar denominated self-sustaining subsidiaries on OCI, therefore a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2014 at an average rate of 2.1%.

The Company s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2014. A total of $2,000 million of future fixed rate term debt issuances have been hedged at an average government bond rate of 4.4%. Further, many of the Company s existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

At December 31, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would not have had an impact (2009 $2 million increase) in earnings and would have caused a $178 million increase (2009 $197 million increase) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2010, and a $22 million decrease (2009 $26 million decrease) in earnings due to increased interest expense related to the Company s variable rate debt outstanding at December 31, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas / NGLs) that impact earnings from its ownership in the Aux Sable natural gas processing plant through 2011.

The Company has defined EaR limits for different components of businesses exposed to commodity price risk. The calculation of these limits reflect physical and financial derivatives as well as physical transportation and storage capacity contracts accounted for as executory contracts in the consolidated financial statements. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from commodity price risk over a one month period:

	2010	2009
(millions of Canadian dollars)		
Average EaR during the year	**22**	22
High EaR during the year	**29**	32
Low EaR during the year	**16**	16
Closing EaR at year end	**25**	19

TOTAL DERIVATIVE INSTRUMENTS

The following tables summarize the balance sheet location and fair value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges as at December 31, 2010 or December 31, 2009.

December 31, 2010	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	**4**	**15**	**111**	**130**
Interest rate contracts	**6**			**6**
Commodity contracts			**33**	**33**
Other contracts			**1**	**1**
	10	**15**	**145**	**170**
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	**18**	**100**	**275**	**393**
Interest rate contracts	**67**			**67**
Commodity contracts			**2**	**2**
	85	**100**	**277**	**462**
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	**(4)**		**(11)**	**(15)**
Interest rate contracts	**(72)**			**(72)**
Commodity contracts			**(51)**	**(51)**
	(76)		**(62)**	**(138)**
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	**(47)**		**(3)**	**(50)**
Interest rate contracts	**(80)**			**(80)**
Commodity contracts			**(3)**	**(3)**
	(127)		**(6)**	**(133)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**(29)**	**115**	**372**	**458**
Interest rate contracts	**(79)**			**(79)**

Commodity contracts			**(19)**	**(19)**
Other contracts			**1**	**1**
	(108)	**115**	**354**	**361**

December 31, 2009	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	4	14	52	70
Interest rate contracts	34		2	36
Commodity contracts			22	22
	38	14	76	128
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	25	80	285	390
Interest rate contracts	90			90
Commodity contracts	1		2	3
Other contracts	1		1	2
	117	80	288	485
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	(2)		(3)	(5)
Interest rate contracts	(68)			(68)
Commodity contracts	(17)		(33)	(50)
	(87)		(36)	(123)
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	(21)			(21)
Interest rate contracts	(15)			(15)
Commodity contracts	(4)		(2)	(6)
	(40)		(2)	(42)
Total net derivative asset/(liability)				
Foreign exchange contracts	6	94	334	434
Interest rate contracts	41		2	43
Commodity contracts	(20)		(11)	(31)
Other contracts	1		1	2
	28	94	326	448

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

	December 31, 2010		December 31, 2009	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards purchase *(millions of United States dollars)*	**2011 2020**	**1,185**	2010 2019	1,078
U.S. dollar forwards sell *(millions of United States dollars)*	**2011 2020**	**3,516**	2010 2020	3,102
Interest rate contracts *(millions of Canadian dollars)*	**2011 2029**	**10,772**	2010 2029	6,022
Commodity contracts Energy *(bcfe)*	**2011 2013**	**41**	2010 2011	464
Commodity contracts Power *(MW/H)*	**2011 2024**	**2**	2010 2024	38

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

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

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Amount of Unrealized Gain/(Loss) Recognized in OCI		
Cash Flow Hedges		
Foreign exchange contracts	**(25)**	(116)
Interest rate contracts	**(172)**	73
Commodity contracts	**97**	(37)
Other contracts	**(1)**	3
Net Investment Hedges		
Foreign exchange contracts	**19**	24
Total unrealized loss recognized in OCI	**(82)**	(53)
Amount of Gain/(Loss) Reclassified from AOCI to Earnings		
Foreign exchange contracts 1	**(7)**	(4)
Interest rate contracts 2	**68**	(31)
Commodity contracts 3	**(95)**	(79)
Other contracts	**1**	3
Total loss reclassified from AOCI to earnings	**(33)**	(111)

1 *Loss reported within Other Income in the Consolidated Statement of Earnings.*

2 *Gain/(loss) reported within Interest Expense in the Consolidated Statement of Earnings.*

3 *Loss reported within Commodity costs in the Consolidated Statement of Earnings.*

The Company estimates that $71 million of accumulated other comprehensive loss related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2010.

Non-Qualifying Derivatives

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

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Foreign exchange contracts 1	**33**	232	35
Interest rate contracts 2	**(2)**	2	
Commodity contracts 3	**(5)**	(88)	122
Total unrealized derivative fair value gain	**26**	146	157

1 *Gain reported within Other Income in the Consolidated Statement of Earnings.*

2 *Gain/(loss) reported within Interest Expense in the Consolidated Statement of Earnings.*

3 *Gain/(loss) reported within Commodity costs in the Consolidated Statement of Earnings.*

Additional information regarding the Company s derivative instruments is included in Note 24, Fair Value of Financial Instruments.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17)*.

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2011	2012	2013	2014	2015	Thereafter
(millions of Canadian dollars)						
Cash inflows	256	136	151	152	59	43
Cash outflows	(224)	(50)	(45)	(25)	(4)	(52)
Net cash flows	32	86	106	127	55	(9)

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

At December 31, 2010 and 2009, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following geographic regions:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Canadian financial institutions	**373**	474
Non-Canadian financial institutions	**(12)**	(26)
	361	448

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, Fair Value of Financial Instruments.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Balance at beginning of year	**(74)**	(69)
Additional allowance	**(23)**	(29)
Amounts used	**35**	24
Balance at end of year	**(62)**	(74)

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

24. Fair Value of Financial Instruments

The following table summarizes the Company s financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2010	Held for Trading	Available for Sale[1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value[2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**242**							**242**	**242**
Accounts receivable and other	**145**		**2,113**			**25**	**423**	**2,706**	**2,283**
Long-term investments		**54**	**339**	**181**			**1,624**	**2,198**	**520**
Deferred amounts and other assets	**277**		**334**			**185**	**2,090**	**2,886**	**462**
Liabilities									
Short-term borrowings					**326**			**326**	**326**
Accounts payable and other	**62**				**2,393**	**76**	**157**	**2,688**	**2,531**
Interest payable					**117**			**117**	**117**
Long-term debt					**13,715**			**13,715**	**14,770**
Non-recourse long-term debt					**1,131**			**1,131**	**1,298**
Other long-term liabilities	**6**					**127**	**1,340**	**1,473**	**133**

December 31, 2009	Held for Trading	Available for Sale[1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value[2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	327							327	327
Accounts receivable and other	76		2,054			52	302	2,484	2,182
Long-term investments		54	6	181			2,071	2,312	187
Deferred amounts and other assets	288					197	1,940	2,425	485
Liabilities									
Short-term borrowings					508			508	508
Accounts payable and other	36				2,237	87	103	2,463	2,360
Interest payable					104			104	104
Long-term debt					12,467			12,467	13,773
Non-recourse long-term debt					1,221			1,221	1,250
Other long-term liabilities	2					40	1,165	1,207	42

1 Classified as Other Investments carried at Cost under U.S. GAAP.

2 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.

The fair value of financial instruments reflects the Company s best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company s long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

FAIR VALUE OF DERIVATIVES

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

Level 1

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

Level 2

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

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

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts		**130**		**130**
Interest rate contracts		**6**		**6**
Commodity contracts		**5**	**28**	**33**
Other contracts			**1**	**1**
		141	**29**	**170**
Long-term derivative assets				
Foreign exchange contracts		**393**		**393**
Interest rate contracts		**67**		**67**
Commodity contracts			**2**	**2**
		460	**2**	**462**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts		**(15)**		**(15)**
Interest rate contracts		**(72)**		**(72)**
Commodity contracts	**(9)**	**(2)**	**(40)**	**(51)**
	(9)	**(89)**	**(40)**	**(138)**
Long-term derivative liabilities				
Foreign exchange contracts		**(50)**		**(50)**
Interest rate contracts		**(80)**		**(80)**
Commodity contracts		**(1)**	**(2)**	**(3)**
		(131)	**(2)**	**(133)**
Total net derivative asset/(liability)				
Foreign exchange contracts		**458**		**458**
Interest rate contracts		**(79)**		**(79)**
Commodity contracts	**(9)**	**2**	**(12)**	**(19)**
Other contracts			**1**	**1**
	(9)	**381**	**(11)**	**361**

December 31, 2009	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts		70		70
Interest rate contracts		36		36
Commodity contracts	2		20	22
	2	106	20	128
Long-term derivative assets				
Foreign exchange contracts		390		390
Interest rate contracts		90		90
Commodity contracts			3	3
Other contracts		2		2
		482	3	485
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts		(5)		(5)
Interest rate contracts		(68)		(68)
Commodity contracts	(2)		(48)	(50)
	(2)	(73)	(48)	(123)
Long-term derivative liabilities				
Foreign exchange contracts		(21)		(21)
Interest rate contracts		(15)		(15)
Commodity contracts		(3)	(3)	(6)
		(39)	(3)	(42)
Total net derivative asset/(liability)				
Foreign exchange contracts		434		434
Interest rate contracts		43		43
Commodity contracts		(3)	(28)	(31)
Other contracts		2		2
		476	(28)	448

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

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of year	**(28)**	53
Total gains/(losses), unrealized		
Included in earnings 1	**19**	(27)
Included in OCI	**3**	7
Settlements	**(5)**	(61)
Level 3 net derivative liability at end of year	**(11)**	(28)

1 Gain/(loss) reported within Commodity Costs in the Consolidated Statement of Earnings.

2 The Company s policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2010 or 2009.

25. Capital Disclosures

The Company defines capital as shareholders equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and non-controlling interests less cash and cash equivalents (excluding cash and cash equivalents from joint ventures and other interests not exclusively controlled by the Company). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company s definition of capital as it is not controlled or managed exclusively by the Company.

The Company s capital is calculated as follows:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Short-term borrowings	**326**	508
Long-term debt (includes current portion)	**13,810**	12,570
Non-controlling interests	**658**	727
Shareholders equity 1	**8,601**	7,958
Cash and cash equivalents	**(172)**	(258)
	23,223	21,505

1 Excludes AOCI and reciprocal shareholdings.

The Company s objectives when managing capital are to maintain flexibility among: enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; and, providing acceptable returns to shareholders. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2010, including short-term borrowings but excluding non-recourse short and long-term debt, was 65.0% compared with 64.1% at the end of 2009.

The Company must adhere to covenants in its credit facilities that are used to backstop its commercial paper program. These covenants include maintaining a minimum consolidated shareholders equity balance of $1,000 million and an unconsolidated debt to unconsolidated shareholders equity ratio of less than 1.5. As at December 31, 2010, the Company was in compliance with these covenants.

Under terms of the Company s Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. Total consolidated capitalization consists of shareholders equity, long-term debt, non-controlling interests and future income tax. As at December 31, 2010, the Company was in compliance with this covenant.

26. Income Taxes

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings before income taxes	**1,221**	1,868	1,837
Combined statutory income tax rate	**28.9%**	30.5%	31.3%
Income taxes at statutory rate	**353**	570	575
Increase/(decrease) resulting from:			
Future income taxes related to regulated operations	**(62)**	(68)	(15)
Higher/(lower) foreign tax rates	**(22)**	(61)	3
Tax rates and legislated tax changes	**(23)**	(58)	(11)
Non-taxable items, net	**(2)**	11	2
Sale of investments		(99)	(82)
Other	**7**	11	37
Income taxes	**251**	306	509
Effective income tax rate	**20.6%**	16.4%	27.7%

COMPONENTS OF FUTURE INCOME TAXES

December 31,	**2010**	2009
(millions of Canadian dollars)		
Net Future Income Tax Liabilities/(Assets)		
Differences in accounting and tax bases of property, plant and equipment	**1,468**	1,346
Differences in accounting and tax bases of investments	**479**	407
Regulatory assets/(liabilities)	**340**	319
Financial instruments	**105**	121
Loss carryforwards	**(81)**	(138)
Other	**56**	29
Net Future Income Tax Liability	**2,367**	2,084

Net future income tax liability of $2,367 million (2009 $2,084 million) is comprised of future income tax liabilities of $2,447 million (2009 $2,211 million) net of future income tax assets of $80 million (2009 $127 million).

At December 31, 2010, the Company has recognized the benefit of unused tax loss carryforwards of $248 million (2009 $425 million) of which $246 million start to expire in 2019 and beyond.

GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**711**	954	624
United States	**379**	334	419
Other	**131**	580	794
	1,221	1,868	1,837
Current income taxes			
Canada	**(29)**	49	141
United States	**37**	35	43
Other	**5**	4	67
	13	88	251
Future income taxes			
Canada	**134**	117	92
United States	**104**	101	166
	238	218	258
Current and future income taxes	**251**	306	509

27. Post Employment Benefits

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2010 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members years of service and final average remuneration. These benefits are partially inflation indexed after a member s retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2009	December 31, 2010
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2009	December 31, 2010

The defined benefit pension plan costs have been determined based on management s best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

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

Post-employment Benefits Other than Pensions

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

DEFINED BENEFIT PLANS

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

	Pension Benefits		OPEB	
December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**1,119**	1,075	**170**	179
Service cost	**48**	53	**5**	4
Interest cost	**72**	71	**11**	11
Amendments			**6**	
Employees contributions			**1**	1
Actuarial loss/(gain) 1	**145**	(13)	**12**	(1)
Benefits paid	**(52)**	(51)	**(7)**	(8)
Effect of foreign exchange rate changes	**(9)**	(16)	**(3)**	(16)
Benefit obligation at end of year	**1,323**	1,119	**195**	170
Change in Plan Assets				
Fair value of plan assets at beginning of year	**1,167**	1,141	**38**	46
Actual return on plan assets 1	**127**	51	**2**	6
Employer s contributions	**89**	44	**9**	9
Employees contributions			**1**	1
Benefits paid	**(52)**	(51)	**(7)**	(8)
Other	**(1)**	(1)		(8)
Effect of foreign exchange rate changes	**(6)**	(17)	**(2)**	(8)
Fair value of plan assets at end of year	**1,324**	1,167	**41**	38
Funded Status				
Benefit obligation	**(1,323)**	(1,119)	**(195)**	(170)
Fair value of plan assets	**1,324**	1,167	**41**	38
Overfunded/(Underfunded) status at end of year	**1**	48	**(154)**	(132)
Contribution after measurement date		14		1
Unamortized prior service cost	**4**	6	**6**	
Unamortized transitional obligation/(asset)	**(11)**	(13)	**8**	9
Unamortized net loss	**307**	161	**22**	12
Net amount recognized in the Consolidated Statement of Financial Position at end of year	**301**	216	**(118)**	(110)
Presented as follows:				
Deferred Amounts and Other Assets *(Note 12)*	**301**	216		
Other Long-Term Liabilities *(Note 18)*			**(118)**	(110)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

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

	Pension Benefits			OPEB		
Year ended December 31,	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**5.64%**	6.46%	6.59%	**5.55%**	6.28%	6.42%
Average rate of salary increases	**3.50%**	3.73%	5.00%			

Net Benefit Costs Recognized

	Pension Benefits			OPEB		
Year ended December 31,	**2010**	2009	2008	**2010**	2009	2008
(millions of Canadian dollars)						
Benefits earned during the year	**48**	53	53	**5**	4	5
Interest cost on projected benefit obligations	**72**	71	65	**11**	11	11
Actual return on plan assets	**(127)**	(51)	180	**(2)**	(6)	12
Difference between actual and expected return on plan assets	**47**	(27)	(273)		3	(15)
Amortization of prior service costs	**2**	2	2			
Amortization of transitional obligation	**(2)**	(2)	(2)	**1**	1	1
Amortization of actuarial loss	**19**	21	4	**1**	1	1
Amount charged to EEP 1	**(15)**	(20)	(8)	**(5)**	(5)	(3)
Net defined benefit costs on an accrual basis	**44**	47	21	**11**	9	12
Adjustment to cash basis for amounts in EGD 2			(3)			6
Defined contribution benefit costs	**5**	4	4			
Net benefit cost recognized in the Consolidated Statements of Earnings	**49**	51	22	**11**	9	18

1 EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.

2 Prior to January 1, 2009, the Company recognized pension benefit costs related to its regulated EGD pension plan on the cash basis.

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

	Pension Benefits			OPEB		
Year ended December 31,	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**6.47%**	6.59%	5.65%	**6.31%**	6.42%	5.71%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.30%	**6.00%**	6.09%	6.00%
Average rate of salary increases	**3.73%**	5.00%	5.00%			

MEDICAL COST TRENDS

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	9.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2010
United States Plan	8.0%	4.5%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $29 million in the accumulated post-employment benefit obligations and an increase of $2 million in benefit and interest costs.

A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $23 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

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

Target Mix for Plan Assets

	Liquids Pipelines Pension Plan	Gas Distribution Pension Plan	Enbridge United States Pension Plan
Equity securities	62.5%	52.5%	57.5%
Fixed income securities	32.5%	42.5%	37.5%
Other	5.0%	5.0%	5.0%

Expected Rate of Return on Plan Assets

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
Canadian Plans	**7.25**%	7.25%	**6.00%**	6.00%
United States Plan	**7.75**%	7.75%	**6.00%**	6.00%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2010, assets securing pension benefits were invested 60.2% (2009 54.7%) in equity securities, 33.8% (2009 34.0%) in fixed income securities and 6.0% (2009 11.3%) in other. OPEB assets securing OPEB benefits were invested 51.2% (2009 60.5%) in equity securities and 48.8% (2009 39.5%) in fixed income securities.

[redacted]

Pension Benefits					
[redacted]	**10**			**10**	[redacted]
		97		**97**	
	4			**4**	
	151			**151**	
	149			**149**	
	47			**47**	
	163			**163**	
	26	**80**		**106**	
	147	**76**		**223**	
	221	**19**		**240**	
			65	**65**	
			68	**68**	
				1	
	918	**272**	**133**	**1,324**	
OPEB					
	20			**20**	
	9			**9**	
		12		**12**	
	29	**12**		**41**	

1 Level 1 assets include assets with quoted prices in active markets for identical assets.

2 Level 2 assets include assets with significant observable inputs.

3 Level 3 assets include assets with significant unobservable inputs.

4 The fair value of the investment in United States Limited Partnership Global Infrastructure Fund is established through the use of valuation models.

5 The fair value of refundable taxes receivable approximates carrying value due to the nature of the receivable and the short period to maturity.

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

[redacted]

PLAN CONTRIBUTIONS BY THE COMPANY

[redacted]			
[redacted]	89	[redacted]	9
[redacted]	90	[redacted]	10

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

[redacted]

28. Other Income

[redacted]		[redacted]
[redacted]	132	[redacted]
[redacted]	81	[redacted]
[redacted]	80	[redacted]
[redacted]	37	[redacted]
[redacted]	15	[redacted]
[redacted]	5	[redacted]
[redacted]		[redacted]
[redacted]	24	[redacted]
[redacted]	374	[redacted]

29. Changes in Operating Assets and Liabilities

[redacted]		[redacted]
[redacted]	(478)	[redacted]
[redacted]	(42)	[redacted]
[redacted]	(99)	[redacted]
[redacted]	283	[redacted]
[redacted]	13	[redacted]
[redacted]	60	[redacted]
[redacted]	(263)	[redacted]

30. Related Party Transactions

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

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows:

[redacted]	[redacted]	[redacted]
[redacted]	**332**	[redacted]
[redacted]	**7**	[redacted]
[redacted]	**339**	[redacted]

At December 31, 2010, the Company has accounts receivable of $29 million (2009 $38 million) from EEP and nil (2009 $1 million) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty. At December 31, 2009, there was no amount outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Alliance Pipeline Canada	**25**	24	24
Alliance Pipeline US	**17**	18	17
Vector Pipeline	**28**	29	27
	70	71	68

Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Purchases	**2**	16	52
Sales		(6)	(7)
	2	10	45

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., formerly Enbridge Gas Services Inc. and Enbridge Gas Services (US) Inc., respectively, subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Alliance Pipeline Canada	**13**	9	9
Alliance Pipeline US	**9**	7	7
Vector Pipeline	**10**	16	16
	32	32	32

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Purchases	**151**	80	24
Sales	**(3)**	(7)	(9)
	148	73	15

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2010, the Company had substantially met all funding commitments.

The Company funded 66.7% of the project s equity requirements through EELP, an equity investee. The Company also provided a $346 million (US$347 million) (2009 $282 million (US$270 million)) loan to EEP for debt financing related to the construction. At December 31, 2010, $334 million is included in Deferred Amounts and Other Assets with the remaining $12 million included in Accounts Receivable and Other (2009 $282 million included in Accounts Receivable and Other). The loan, denominated in United States dollars, bears interest based on variable short-term rates.

During the year the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $40 million (US$39 million) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million (2008 $12 million).

ENBRIDGE INCOME FUND HOLDINGS

In December 2010, EIFH entered into an agreement with Enbridge Management Services Inc. (EMSI), a wholly owned subsidiary of the Company, to provide management and administrative services to EIFH. EMSI also provides management and administrative services to EIF. Provided that EIF is paying a base fee to EMSI for the services received by EIF, there is no fee payable to EMSI by EIFH as was the case for the period ended December 31, 2010.

LAKEHEAD LINE 6B LEAK

In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $18 million for the year ended December 31, 2010.

31. Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totaling $1,686 million which are expected to be paid within the next 5 years.

ENBRIDGE ENERGY PARTNERS, L.P.

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

Enbridge holds an approximate 25.5% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

Line 6B Leak

On July 26, 2010, a crude oil release on Line 6B of EEP s Lakehead System was reported near Marshall, Michigan. EEP currently estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The 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 previously estimated 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. EEP subsequently revised its estimate from US$430 million to US$550 million ($96 million after-tax net to Enbridge) based on a review of costs and commitments incurred, as well as additional information concerning the requirements for environmental restoration and remediation. The assumptions made including the scope of remediation efforts, the duration that resources will be required to complete the work, weather conditions and other similar factors underlying EEP s estimates are subject to further modification and could result in additional revisions to EEP s estimates. Although EEP met the deadlines established by the Environmental Protection Agency (EPA) for clean up and remediation of areas affected by the crude oil release, it has the potential of incurring additional costs in connection with this incident, including fines and penalties.

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, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. 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 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 assumptions or in any or all of the categories described above, including modified or revised requirements from regulatory agencies or other factors.

Insurance Recoveries

The Company maintains commercial liability insurance coverage that is consistent with coverage considered customary for its industry. The commercial liability insurance covers costs associated with environmental incidents such as those incurred for the leaks from Line 6B and 6A, excluding costs for fines and penalties. EEP is included in Enbridge s comprehensive insurance program that has an aggregate limit of US$650 million of pollution liability through the policy renewal date of May 1, 2011. The remaining coverage under the Company s existing insurance policies is approximately US$70 million. The Company does not maintain insurance coverage for interruption of operations except for water crossings; therefore, EEP will not recover approximately US$16 million of revenues lost while Line 6B and 6A were not in service. Apart from the amounts for which EEP is not insured, it is anticipated that substantially all of the costs incurred from the leaks will ultimately be recoverable under the Company s existing insurance policies. EEP expects to record a receivable for any amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery is 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 is remediating on 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, approximately 20 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B 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 a United States state court. The Company believes this action or claim has been resolved pursuant to an agreed interim order.

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

EGD had been 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 Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge s decision and ordered a new trial to be conducted before a different judge. EGD commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed EGD s motion, meaning that the Superior Court s decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

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.

32. Guarantees

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM s formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company s financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. 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

[redacted]		[redacted]
	963	
	970	
	(52)	
	20	
	4	
	(172)	
	25	
	795	
	942	
	(147)	
	795	
	2.55	
	2.52	