ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

CONSOLIDATED EARNINGS

(millions of Canadian dollars, except per share amounts)	**2008**	2007	2006
Liquids Pipelines	**328.0**	287.2	274.2
Gas Pipelines	**48.5**	69.7	61.2
Sponsored Investments	**111.7**	96.9	86.8
Gas Distribution and Services	**300.6**	179.4	173.7
International	**608.2**	95.1	83.2
Corporate	**(76.2)**	(28.1)	(63.7)
Earnings Applicable to Common Shareholders	**1,320.8**	700.2	615.4
Earnings per Common Share	**3.67**	1.97	1.81
Diluted Earnings per Common Share	**3.64**	1.95	1.79

Earnings applicable to common shareholders were $1,320.8 million for the year ended December 31, 2008, or $3.67 per share, compared with $700.2 million, or $1.97 per share, for the same period in 2007. The increase in earnings resulted from allowance for equity funds used during construction (AEDC) in Liquids Pipelines, a higher contribution from Enbridge Gas Distribution (EGD) and unrealized fair value gains on derivative financial instruments in Aux Sable and Energy Services, partially offset by decreased earnings from International as the Company sold its interest in Compañía Logística de Hidrocarburos CLH, S.A. (CLH) in the second quarter of 2008. Earnings for the year ended December 31, 2008 also reflected a $556.1 million after-tax gain on the sale of CLH, partially offset by the recognition of a $32.2 million income tax charge as a result of an unfavourable court decision related to previously owned U.S. pipeline assets.

Earnings applicable to common shareholders were $700.2 million for the year ended December 31, 2007, or $1.97 per share, compared with $615.4 million, or $1.81 per share, in 2006. The $84.8 million increase was primarily due to colder than normal weather and strong performance at EGD, lower corporate interest expense and increased earnings at Enbridge Energy Partners, L.P. (EEP). The 2007 results also included a significant benefit from favorable legislated Canadian tax changes enacted in 2007. The positive factors were partially offset by lower contributions from the Aux Sable natural gas fractionation facility and Energy Services.

FORWARD LOOKING INFORMATION

Forward looking information, or forward looking statements, have been included in this Management's Discussion and Analysis (MD&A) to provide Enbridge Inc. (Enbridge or the Company) shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. 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; anticipated in-service dates and weather.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, 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, which represent earnings 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 provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings and adjusted earnings for each of the segments are not measures that have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliation section for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

(millions of Canadian dollars, except per share amounts)	**2008**	2007	2006
Liquids Pipelines	**332.1**	286.0	274.2
Gas Pipelines	**45.7**	64.4	61.2
Sponsored Investments	**100.9**	86.5	74.3
Gas Distribution and Services	**204.3**	168.9	177.7
International	**52.1**	89.9	83.2
Corporate	**(57.8)**	(59.2)	(77.7)
Adjusted earnings	**677.3**	636.5	592.9
Adjusted earnings per Common Share	**1.88**	1.79	1.74

Adjusted earnings were $677.3 million, or $1.88 per share, for the year ended December 31, 2008, compared with $636.5 million, or $1.79 per share, for the year ended December 31, 2007.

Significant operating factors that increased adjusted earnings in 2008 included:

- New facilities within Liquids Pipelines as well as AEDC on Southern Lights Pipeline and, within Enbridge System, on both Southern Access Mainline Expansion and Alberta Clipper Project.
- Increased Aux Sable adjusted earnings due to strong fractionation margins which enabled the Company to recognize earnings from the upside sharing mechanism.
- Higher incentive income and increased earnings at EEP primarily due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and a greater ownership interest.
- Improved earnings in Energy Services resulting from market conditions which enabled higher margins to be captured on storage and transportation contracts as well as increased transportation and storage volumes.

Significant operating factors that decreased adjusted earnings in 2008 included:

- Decreased earnings from International as a result of the sale of CLH in the second quarter of 2008.
- Lost revenue from Enbridge Offshore Pipelines (Offshore) as a result of Hurricanes Gustav and Ike.

2008 Commercial and Construction Accomplishments:

- Alberta Clipper, Southern Lights Pipeline and Line 4 Extension were approved by the National Energy Board (NEB) and construction began on the Canadian portion of Alberta Clipper Project, Line 4 Extension and various segments of Southern Lights Pipeline.
- First phase of the U.S. Southern Access Expansion Project has been completed on schedule and construction commenced on Phase 2 of Southern Access Expansion Project.
- Waupisoo Pipeline, which was completed one month ahead of schedule and on budget.
- Spearhead Pipeline expansion commenced.
- Project financing of US$1.3 billion and $0.4 billion secured for Southern Lights Pipeline.

CORPORATE STRATEGY

CORPORATE VISION AND KEY OBJECTIVE

Enbridge is an energy delivery company that transports natural gas and crude oil, which are used for many purposes, including to heat homes, power transportation systems and provide fuel and feedstock for industries. The Company's vision is to be North America's leading energy delivery company and its key objective is to generate superior shareholder value. The Company will deliver superior shareholder value through an investment proposition consisting of:

- industry leading earnings per share growth rate;
- a low risk commercial business model; and
- a balanced combination of near-term dividend income and capital appreciation.

STRATEGY

Enbridge's 2008 Strategic Plan consisted of four key strategic priorities to generate superior shareholder value and position the Company for the energy environment of the future.

1. **Expand existing core businesses**

   Developing and operating energy delivery infrastructure assets remains the Company's core competency and strength. To capitalize on its asset position, Enbridge will pursue opportunities in both its liquids and natural gas delivery businesses. The Company will aggressively focus on the expansion and extension of its liquids pipeline and terminaling businesses. The Company will also seek to capture additional growth opportunities associated with its gas businesses to maintain as much diversification as is prudent. Strategies for each core business are included in the sections to follow.

2. **Focus on operations**

   Effective day-to-day management of operations is integral to Enbridge's broader strategy. Achieving the Company's long-term objectives depends on its ability to consistently deliver safe, cost-effective and high quality service to customers and meet the broader expectations of communities it serves. Operational excellence will ensure that the Company is able to deliver consistent and predictable operating and financial performance while rapidly growing its asset and earnings base. Enbridge will continue its focus on operational excellence, including cost efficiency, safety and customer service.

3. **Mitigating and managing execution risk**

   Executing Enbridge's unprecedented capital program demands effective strategies for mitigating and managing project development risk. Key priorities include enhanced project management systems and processes, proactive human resource planning and an increased focus on social investment, to both facilitate project development and meet the expectations of the Company's stakeholders.

4. **Developing new platforms for longer-term growth**

   In the longer term, developing new business platforms will be important to maintaining growth and diversification within the Company. New platforms currently being pursued include renewable energy (wind and solar), CO2 transportation and sequestration and investment in smaller start-up entities to enable the development of new technologies that complement the Company's core operations.

To successfully pursue these strategies, the Company must also mitigate other risks. These risks, and the Company's strategies for managing them, are described under Risk Management.

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 benchmarks before being pursued.

COMPETITIVE ADVANTAGE

The Company's ability to execute its strategy and realize its corporate vision depends primarily on three key strengths. These include the strategic position of the Company's major assets, the diversification of its businesses and its consistent focus on operational excellence including customer service.

The Company's assets are well positioned in North America. In the Liquids Pipelines business, the Company operates a major conduit between U.S. markets and the attractive oil sands reserves in western Canada. Enbridge has economies of scale and scheduling flexibility because of its multiple separate lines and the flexibility to move over 95 different grades of crude oil. Enbridge's existing right of way is valuable in developing major expansion projects due to increasing environmental and landowner challenges in securing new or expanded energy corridors. Also, the Company serves a diversity of markets because of the extent and reach of its pipeline systems. The gas businesses are also well located. The Ontario gas utility franchise in Toronto benefits from significant customer addition rates due to immigration and urbanization.

The Company's sources of earnings and growth are diversified among liquids pipelines, gas pipelines, gas distribution and international investments. As well, the Company is actively exploring new growth platforms that would further diversify and complement existing core businesses.

The Company is focused on adding value for customers and improving customers' profitability. This focus has aligned the Company with supply-demand fundamentals, which have consistently formed a basis for the Company's strategy. The Company seeks to provide value to customers in a variety of innovative ways, including provision of access to new markets for producers and new sources of supply for refiners, diversifying the supply of diluent required for transportation of heavy crude and protection of batch quality and value.

GROWTH PROJECTS

The thrust of the Company's current strategy is growth through development and construction of new infrastructure. The Company is advancing the development of a number of organic growth projects, some of which are summarized below, which support annual organic earnings per share growth rates averaging 10% 'plus' over the 2007 to 2012 time frame. These projects are at various stages of development; some are recently completed and in service.

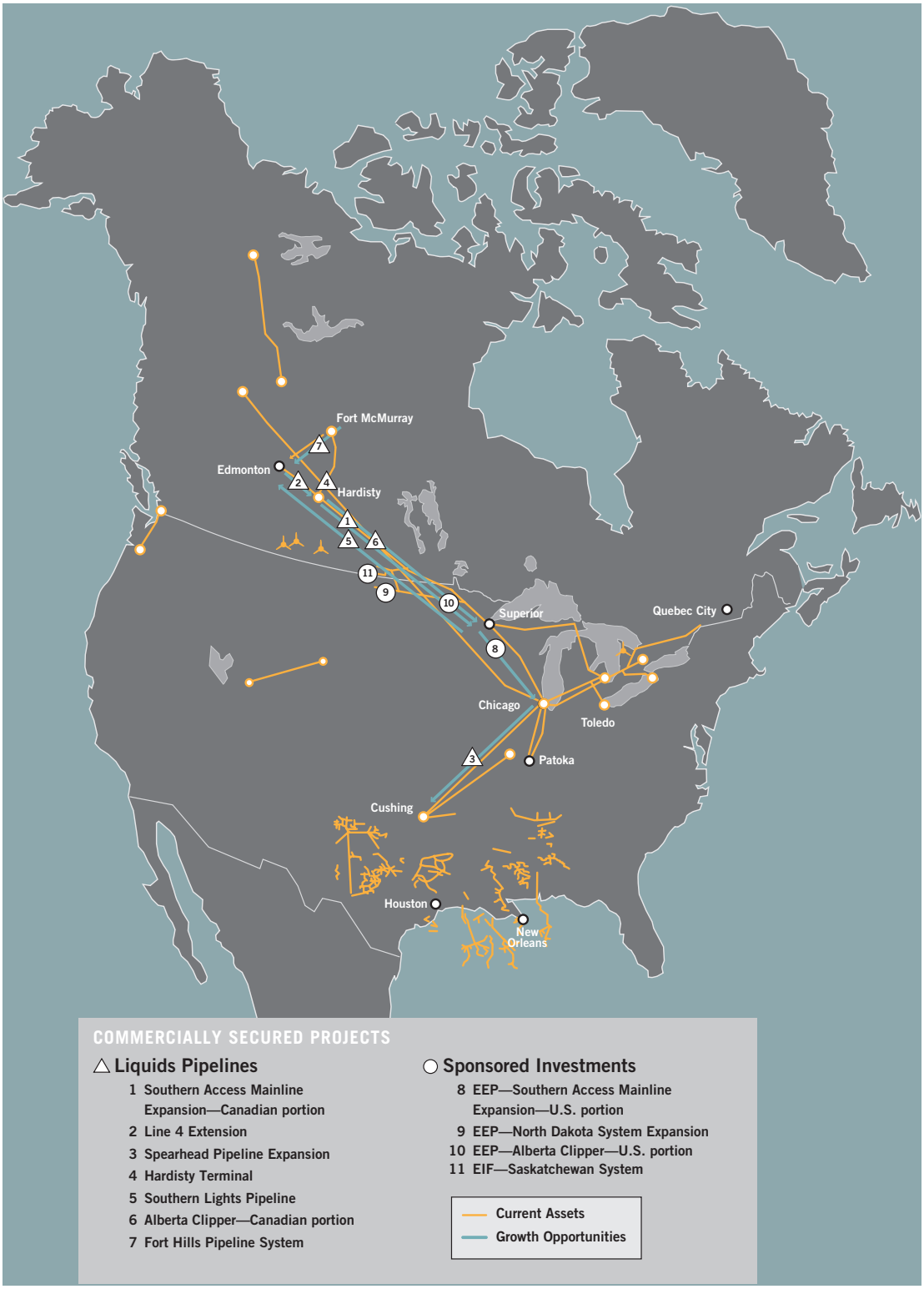
While different milestones are relevant to each, for simplicity management has classified projects into two categories – Commercially Secured and Under Development. Commercially Secured projects, including those being undertaken by EEP, are largely expected to be completed within the next two years. Projects Under Development are those which the Company believes it has a reasonable probability of competitively winning but has not yet completed commercial terms for. While Enbridge will undertake acquisitions that are accretive to earnings on an opportunistic basis, growth project execution remains the Company's primary near term focus. The following table summarizes Commercially Secured projects that have not yet been placed into service.

Commercially Secured Projects [1]	Estimated Capital Cost [2]	Expenditures to Date	Expected In-Service Date	Status
(in billions of Canadian dollars unless stated otherwise)				
Liquids Pipelines				
1. Southern Access Mainline Expansion – Canadian portion	$0.2 billion	$0.2 billion	2008	Substantially complete
2. Line 4 Extension	$0.3 billion	$0.2 billion	Early 2009	Under construction
3. Spearhead Pipeline Expansion	US$0.1 billion	US$0.1 billion	First half of 2009	Under construction
4. Hardisty Terminal	$0.6 billion	$0.4 billion	2009 (in stages)	Under construction
5. Southern Lights Pipeline	$0.5 billion + US$1.7 billion	$0.3 billion + US$0.9 billion	Light Sour Line – Early 2009; Diluent Line – Late 2010	Under construction
6. Alberta Clipper – Canadian portion	$2.4 billion	$0.8 billion	Mid-2010	Under construction
7. Fort Hills Pipeline System	~$2.0 billion	$0.1 billion	No earlier than 2012	Being reevaluated
Sponsored Investments				
8. EEP – Southern Access Mainline Expansion – U.S. portion	US$2.1 billion	US$1.9 billion	2008 - 2009 (in stages)	Under construction
9. EEP – North Dakota System Expansion	US$0.1 billion	No significant expenditures to date	Q1 2010	Under construction
10. EEP – Alberta Clipper – U.S. portion	US$1.2 billion	US$0.1 billion	Mid-2010	Awaiting regulatory approval
11. EIF – Saskatchewan System	$0.1 billion	No significant expenditures to date	Q3 2010	Pre-construction

1 Descriptions of each project are included in the strategy section for each business segment.

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

Risks related to the development and completion of organic growth projects are described under Risk Management.


Fort McMurray
Edmonton
Hardisty
Superior
Quebec City
Chicago
Toledo
Patoka
Cushing
Houston
New Orleans
COMMERCIALLY SECURED PROJECTS
Liquids Pipelines
1 Southern Access Mainline Expansion—Canadian portion
2 Line 4 Extension
3 Spearhead Pipeline Expansion
4 Hardisty Terminal
5 Southern Lights Pipeline
6 Alberta Clipper—Canadian portion
7 Fort Hills Pipeline System
Sponsored Investments
8 EEP—Southern Access Mainline Expansion—U.S. portion
9 EEP—North Dakota System Expansion
10 EEP—Alberta Clipper—U.S. portion
11 EIF—Saskatchewan System
Current Assets
Growth Opportunities

DISRUPTION OF FUNCTIONING OF CAPITAL MARKETS

Multiple events during 2008 involving numerous financial institutions have restricted liquidity in the capital markets. Despite efforts by government agencies to provide liquidity to the financial sector, capital markets currently remain constrained. Given the Company's current and future growth and related funding requirements, these events and market conditions pose potential challenges. The Company's strong, predictable, internally generated cash flows; common share issuances under the Company Dividend Reinvestment and Share Purchase Plan; and access to adequate and recently increased committed credit facilities from diversified sources assist in mitigating these challenges. Maintaining the Company's investment grade credit rating may also support continued access to capital markets and debt refinancing at reasonable terms, if required. See Sensitivity Analysis and Risk Management – Credit Risk sections.

Decline in Commodity Prices

Since the end of the third quarter, commodity prices have significantly declined. As an energy transportation company, Enbridge has very limited direct exposure to commodity price changes and the Company employs comprehensive risk management practices to largely fix and mitigate any residual commercial exposures. Most significantly, the Company's assets and operations are largely secured by high quality shipper volume commitments. Similarly, liquids pipelines growth projects under construction are commercially secured with limited volume sensitivity and are therefore not expected to be significantly impacted by commodity price declines. Low commodity prices are resulting in the delays or cancellation of some oil and gas development and expansion projects. Should current trends continue long term, opportunities for future growth projects may be adversely affected. See Liquidity and Capital Resources.

DIVIDENDS

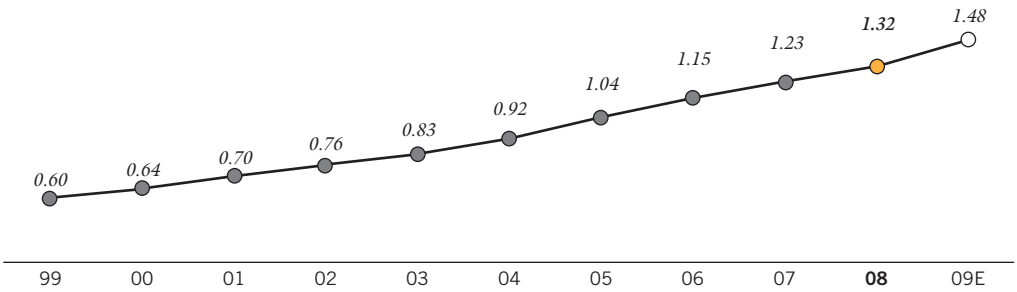
The Company has paid common share dividends since its inception. Based on estimated 2009 dividends, the rate of increase has averaged 10.1% since 1953. The Company's dividend payout ratio reflects a strong and stable long-term outlook for its business. Despite current economic conditions, in December 2008 the Company announced a 12% increase in its quarterly dividend to $0.37 per common share, or $1.48 annualized. The Company continues to target a pay out of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2009 pay out should be near the midpoint of the range. In 2008, dividends paid per share were 70% of adjusted earnings per share (2007 – 69%, 2006 – 66%).

The following chart shows dividends per share for the last 10 years, as well as estimated dividends for 2009, based on the quarterly dividend of $0.37 per common share declared by the Board of Directors on December 3, 2008.

CORPORATE SOCIAL RESPONSIBILITY

Enbridge has a strong foundation of core values and corporate social responsibility policies and practices. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical 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.

Dividends per Common Share *(dollars per share)*



A comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees. Examples include compliance with applicable Sarbanes-Oxley requirements and the Canadian securities regulators' corporate governance guidelines and rules, the use of internal and external reviews and audits to assess each business segment's compliance with government regulations and internal policies and management systems, and to provide guidance for making further improvements. Employee and Director compliance with Enbridge's Statement on Business Conduct, a majority of independent Directors on the Company's Board of Directors and plain and open communication with stakeholders are other examples of stewardship and accountability.

Environmental initiatives include pursuing alternative and renewable energy technologies, minimizing pipeline leaks by conducting on-going inspection and maintenance programs and the development of a strategy to reduce greenhouse gas emissions. This strategy involves improving the energy efficiency of pipelines, encouraging the efficient use of natural gas by customers and replacing older cast iron pipe at EGD with new polyethylene mains. Enbridge engages employees on health and safety issues through training, communication programs and the establishment of local and regional Environmental, Health and Safety committees.

Stakeholder relations involves developing and maintaining positive relationships with employees, contractors, suppliers, customers, landowners, investors, community residents, aboriginal communities, business partners, government agencies and regulators, provincial, state and federal legislators, local officials, environmental groups and the media. Initiatives include early-stage project consultation with a variety of stakeholders on organic growth projects and public awareness programs on pipeline safety.

Enbridge supports universal human rights and reinforces this principle with comprehensive policies and practices addressing human rights. For example, Enbridge was one of the first Canadian companies to adopt the Voluntary Principles on Security and Human Rights, which stress the importance of promoting and protecting human rights throughout the world and the constructive role business can play in advancing these goals.

The Company makes voluntary contributions to charitable and non-profit organizations in the areas of: education, health, environment, social services, arts and culture, community leadership and volunteerism, in order to contribute to the economic and social development of communities where Enbridge employees live and work.

While Enbridge is focused on generating long-term value for investors, Corporate Social Responsibility defines the Company's commitment to achieving and sustaining that objective in a socially and environmentally responsible way.

CORE BUSINESSES

The Company's activities are carried out through five business segments:

- Liquids Pipelines, which includes the operation and construction of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons.
- Gas Pipelines, which consists of the Company's interests in natural gas pipelines including Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines.
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF or the Fund) and EEP, both managed by Enbridge.
- Gas Distribution and Services, which consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses.
- International, which includes the Company's energy-delivery investment outside of North America.

LIQUIDS PIPELINES

Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines in Canada and the United States.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge System	**211.5**	202.5	202.3
Athabasca System	**69.1**	53.7	52.8
Spearhead Pipeline	**12.0**	10.0	6.3
Olympic Pipeline	**7.1**	9.9	6.5
Southern Lights Pipeline	**27.6**	6.8	–
Feeder Pipelines and Other	**4.8**	3.1	6.3
Adjusted earnings	**332.1**	286.0	274.2
Enbridge System – impact of tax changes	**–**	1.2	–
Feeder Pipelines and Other – asset impairment loss	**(4.1)**	–	–
Earnings	**328.0**	287.2	274.2

Liquids Pipelines adjusted earnings were $332.1 million in 2008 compared with $286.0 million in 2007. The increase was due primarily to strong contributions from the Enbridge and Athabasca Systems, as well as the recognition of AEDC on Enbridge System and Southern Lights Pipeline.

While under construction, certain regulated pipelines are entitled to recognize AEDC in earnings. These amounts will contribute to earnings throughout the Company's significant growth period and will be collected in tolls once the pipelines are in service. The earnings impact of AEDC for the year ended December 31, 2008 was $17.8 million (2007 – $2.9 million) for Enbridge System and $27.6 million (2007 – $6.8 million) for Southern Lights Pipeline.

Liquids Pipelines adjusted earnings were $286.0 million in 2007 compared with $274.2 million in 2006. The increase was due primarily to strong contributions from Spearhead and Olympic Pipelines, as well as the recognition of AEDC on Southern Lights Pipeline.

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

- In the fourth quarter of 2008, the Company recorded an impairment loss of $4.1 million on Manyberries Pipeline, a small feeder pipeline located in Canada.
- Enbridge System was affected by favorable tax rate changes in 2007.

Liquids Pipelines revenues were $1,170.5 million in the year ended December 31, 2008, an increase of $79.6 million compared with $1,090.9 million in the year ended December 31, 2007. This increase is due to higher base tolls on Enbridge System and the new Waupisoo Pipeline included in the Athabasca System.

Revenues in the Liquids Pipelines segment increased to $1,090.9 million in the year ended December 31, 2007 from $1,048.1 million in the year ended December 31, 2006. The increased revenue was partially due to increased volumes on Spearhead Pipeline and higher tolls on Olympic Pipeline. In addition, revenue reflected full year contribution from Spearhead Pipeline and Olympic Pipeline.

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 five adjacent pipelines with a combined

capacity of approximately 2.0 million barrels per day (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 in 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 2008 was 85% and it is expected to increase in 2009.

Results of Operations

Enbridge System adjusted earnings were $211.5 million for the year ended December 31, 2008 compared with $202.5 million for the year ended December 31, 2007. Enbridge System adjusted earnings increased due to increased tolls from a higher rate base as a result of Southern Access Mainline Expansion entering service on March 31, 2008 and the AEDC recognized while the project was under construction.

Enbridge System adjusted earnings were $202.5 million for the year ended December 31, 2007 compared with $202.3 million for the year ended December 31, 2006. The effect of increased incentive tolling settlement (ITS) metrics bonuses and higher System Expansion Program (SEP) II utilization were offset by increased operating costs and higher taxes in the Terrace component, resulting in consistent earnings in 2007 and 2006.

For the years ended December 31, 2008 and 2006 adjusted earnings equaled earnings. In 2007, Enbridge System earnings increased by $1.2 million as a result of favorable tax rate changes.

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 ITS applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement, the SEP II Risk Sharing Agreement and the Southern Access Expansion Agreement which is recovered via the Mainline Expansion Toll. Tolls on the core mainline system have been governed by incentive tolling settlements since 1995, with the current ITS term being effective through 2009.

The ITS allows the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In addition, performance metrics bonuses and penalties were added to the current ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets and may incur penalties if performance falls short of specified thresholds.

Enbridge achieved total metrics bonuses of approximately $15 million for the year ended December 31, 2008 compared with approximately $11 million and $10 million for the years ended December 31, 2007 and 2006, respectively.

In conjunction with the Terrace Agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The agreements govern both current and future shippers on the pipeline and establish tolls each year 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 rolled into the subsequent year's tolls for collection from shippers at that time and a receivable, referred to as the Transportation Revenue Variance (TRV), is recognized. This basis may affect the timing of recognition of revenues compared with that otherwise expected under GAAP for companies that are not rate-regulated. As at December 31, 2008, $113.6 million (2007 – $143.4 million) was recorded as tolling deferrals.

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

ATHABASCA SYSTEM

Athabasca 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 the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil tankage services, and two large terminals – the Athabasca Terminal located North of Fort McMurray, Alberta and the Cheecham Terminal which is a new hub located 95 kilometres south of Fort McMurray where the Waupisoo Pipeline initiates.

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 and is currently configured to transport approximately 390,000 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 contract provides for volumes and tolls that will achieve an underpinning return on equity based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns as well as the cost of providing service; therefore, Enbridge is recording a receivable in these years. This treatment ensures that the revenue recognized each period is in accordance with the contract. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

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 is currently configured to transport 350,000 bpd, but is ultimately rated for a design capacity of 600,000 bpd, providing Enbridge with opportunities for economic expansion achieved through the addition of pump stations to the line.

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 with significant upside potential as incremental founder and third party volumes are added.

Results of Operations

Earnings for the year ended December 31, 2008 were $69.1 million compared with $53.7 million for the year ended December 31, 2007. The increase in Athabasca System earnings reflected tolls collected on Waupisoo Pipeline since being placed into service at the end of May 2008 and the positive impact of terminal infrastructure additions. The increase in full year earnings was partially offset by higher operating costs.

Earnings for the year ended December 31, 2007 were $53.7 million compared with $52.8 million for the year ended December 31, 2006. The increase was due to earnings from infrastructure additions, partially offset by higher operating costs including increased property taxes and minor leak remediation costs.

SPEARHEAD PIPELINE

The Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of this 125,000 bpd pipeline has steadily increased and with the support of shippers, the Spearhead Pipeline Expansion is underway to increase capacity to 193,000 bpd.

Results of Operations

Earnings increased to $12.0 million for the year ended December 31, 2008 compared with $10.0 million for the year ended December 31, 2007 as a result of higher throughputs and higher tolls on committed volumes.

Earnings increased to $10.0 million for the year ended December 31, 2007 compared with $6.3 million for the year ended December 31, 2006. Spearhead Pipeline commenced operations at the beginning of March 2006; therefore, 2007 earnings reflect a full year of operations as well as increased throughput.

OLYMPIC PIPELINE

In February 2006, Enbridge acquired a 65% interest in the Olympic Pipeline from BP Pipelines (North America) Inc. (BP). Olympic is the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP is the operator of the pipeline.

Results of Operations

Earnings for the year ended December 31, 2008 were $7.1 million compared with $9.9 million for the year ended December 31, 2007. Olympic Pipeline earnings reflected lower average tolls effective July 1, 2008 to compensate for over collection in 2007. Olympic's cost of service tolling methodology requires annual toll adjustments for over or under collection of the cost of service in prior years. 2008 earnings also reflected an increase in pipeline integrity costs.

Earnings for the year ended December 31, 2007 were $9.9 million compared with $6.5 million for the year ended December 31, 2006. Higher tolls as well as a full year contribution from Olympic Pipeline resulted in the $3.4 million increase.

SOUTHERN LIGHTS PIPELINE

This pipeline received regulatory approval in Canada in the first quarter of 2008 and is currently under construction in both the United States and Canada. Upon completion, the 180,000 bpd, 20-inch diameter Southern Lights Pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta.

Results of Operations

The Company is entitled to collect an AEDC in tolls once the pipeline is in service. Earnings for both 2008 and 2007 reflect the AEDC recognized while the project is under construction.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily 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 in Feeder Pipelines and Other were $4.8 million for the year ended December 31, 2008 compared with $3.1 million for fiscal 2007. The increase in adjusted earnings resulted from a decrease in business development expenditures and improved operating results on a number of feeder systems.

Adjusted earnings for the year ended December 31, 2007 were $3.1 million compared with $6.3 million for fiscal 2006. The decrease in earnings was primarily due to increased business development costs related to the Company's organic growth projects.

Earnings for the year ended December 31, 2008 were impacted by an impairment loss of $4.1 million on Manyberries Pipeline.

STRATEGY

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. In addition to incentive tolling models, the Liquids Pipelines strategy focuses proactively on understanding Western Canadian supply and downstream demand fundamentals and then proposing timely new or reconfigured infrastructure solutions to improve customer profitability.

Future Prospects for Liquids

Historically, Western Canada has been a key source of oil supply serving U.S. energy needs. For the past five years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 178 billion barrels compare with Saudi Arabia's proved reserves of approximately 264 billion barrels. The NEB estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.4 million bpd in 2008 and 2007. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. The Canadian Association of Petroleum Producers' (CAPP) December 2008 estimates indicate that future production for the Alberta Oil Sands is expected to steadily increase to more than 1.8 million bpd by 2018 based on a subset of currently approved applications and announced expansions. The Company is actively working with customers to ensure that Enbridge mainline system will allow Canadian crude oil greater access to markets in the United States.

Crude oil price volatility in 2008 has caused some crude oil producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the WCSB declines, immediate need for new pipeline infrastructure will likely decline. In addition to Enbridge's expansions, a significant competitor is expected to complete construction of a pipeline system to Wood River, Illinois. This competing pipeline, together with the Southern Access and Alberta Clipper expansions, may provide sufficient capacity for the near term. In this case, expansion activities will be more modest than experienced over the last several years. Although a number of oil sands projects have announced delays, the supply from the oil sands is forecasted to grow at a steady pace.

Key Components of the Liquids Pipelines Strategy

The Liquids Pipelines strategy is driven by shippers' need for adequate export capacity, market alternatives and economic sources of diluent, and U.S. refiners' need to maintain diversified sources of supply. The five key components of the Liquids Pipelines strategy are discussed below as well as progress made to date and future plans towards further advancing the strategy.

1. Mainline Capacity Development

The Chicago refining market is expected to remain a major export destination for Western Canadian crude. The Company is working with shippers and refiners to further expand this market and markets beyond, both in Canada and the United States, through the Southern Access Mainline Expansion and the Alberta Clipper Project. The Line 4 Extension Project is a third, smaller debottlenecking project that has been undertaken to expand capacity.

Southern Access Mainline Expansion Project

The Southern Access Mainline Expansion Project will ultimately add a total of 400,000 bpd incremental capacity to the mainline system. In Canada, upgrades at 18 pump stations to improve pumping effectiveness are substantially complete. The Company started collecting associated tolls in April 2008.

In the United States, the new 42-inch diameter pipeline from Superior to Delavan, Wisconsin was placed into commercial service and was ready to receive linefill at the end of the first quarter of 2008. In the fourth quarter of 2008 the system began receiving crude, as it was made available by shippers, and is scheduled to be completely filled by the end of the first quarter of 2009. The first stage of the expansion adds capacity of approximately 190,000 bpd to the pipeline and system-wide toll surcharges were effective April 1, 2008 for the facilities that have been put into service. Construction of the second stage of the expansion project from Delavan, Wisconsin to Flanagan, Illinois, started in June 2008 and is on schedule for completion in the first quarter of 2009.

The expected cost of the project, which is fully recoverable in tolls, has decreased to an estimated US$2.3 billion (Enbridge – $0.2 billion, EEP – US$2.1 billion). The estimated capital cost for the Canadian portion was revised from $0.3 billion to $0.2 billion based on refinements to the scope of the project, agreed to with CAPP, to reflect the subsequent approval of the Alberta Clipper Project. Expenditures to date on the Southern Access Mainline Expansion are US$1.9 billion and $0.2 billion on the U.S. and Canadian portions, respectively.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior, Wisconsin generally within or alongside Enbridge's existing right-of-way. The Alberta Clipper Project will interconnect with the existing mainline system in Superior where it will provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing. The project will have an initial capacity of 450,000 bpd, is expandable to 800,000 bpd and will form part of the existing Enbridge System in Canada and the EEP Lakehead System in the United States.

In the first quarter of 2008, Enbridge received NEB approval to construct this 1,607-kilometre (1,000-mile) 36-inch diameter crude oil pipeline. Construction on the Canadian segment of the line commenced in August 2008, with an expected in-service date of mid-2010 and an expected cost of $2.4 billion, including escalation of the original "constant 2007 dollar" cost estimate to current "as spent" dollars, and allowance for funds used during construction (AFUDC). The U.S. segment, to be undertaken by EEP, is awaiting regulatory approval, with construction expected to begin in mid-2009. Subject to regulatory approval, the U.S. segment of the Alberta Clipper project is also expected to be in service in mid-2010. The cost of the U.S. segment is estimated at US$1.2 billion. Enbridge will share in cost overruns or savings against estimates, for costs deemed to be controllable costs. Controllable costs comprise approximately 70% of the total cost estimate.

Line 4 Extension Project

In April 2008 the NEB approved Enbridge's regulatory application for the construction and operation of the $0.3 billion Line 4 Extension project. Subsequent NEB route approval was received in July 2008. Construction commenced in August 2008, with the Line 4 Extension expected to be in service in early 2009.

2. Regional Oil Sands Development

Enbridge continues to be well positioned to capture significant growth from development of the regional infrastructure required to transport oil sands production to local markets or into major export pipelines. Successful execution of this strategy during 2007 and 2008 has further reinforced Enbridge's dominant position in the oil sands and provides increased leverage for future growth. Optimizing the

Athabasca, Waupisoo and Fort Hills Pipelines will form the foundation of development efforts for the next wave of oil sands growth.

Fort Hills Pipeline System

In November 2007, Enbridge was selected by the Fort Hills Energy L.P. (FHELP) as their pipeline and terminaling services provider for both the initial phase of the Fort Hills project and all subsequent expansions. The scope of the Fort Hills Pipeline System is being re-evaluated by FHELP to reflect changing market conditions. The planned in-service date for the initial facilities has been deferred from mid-2011 to no earlier than 2012, subject to sanctioning of the overall project by FHELP.

3. Feeder System Expansions

Expanding the reach and capacity of the feeder pipeline systems will continue to be a priority. A particular focus will be the development of opportunities to expand gathering and feeder systems in Saskatchewan and North Dakota which are being driven by growing production from the Bakken play in the Williston Basin. The Company is advancing this component of its strategy through both the North Dakota System Expansion at EEP and the Saskatchewan System Capacity Expansion discussed in the Sponsored Investments section.

4. New Market Access

Enbridge's successful initiative to provide access for Canadian crude oil to the Cushing market through the acquisition and reversal of the Spearhead Pipeline has provided validation of the value to industry of market optionality. In addition to the planned construction of the Southern Access Extension which is expected to provide access to the Patoka market, Enbridge will continue to pursue new opportunities to provide broader market access for Canadian bitumen and synthetic crudes. Key opportunities being pursued include: Eastern PADD II access into the Michigan and Ohio markets; access to U.S. Gulf Coast refining centers through a combination of smaller incremental opportunities and large volume solutions; PADD I access into the East Coast market near Philadelphia; and the Northern Gateway pipeline to the Pacific Coast.

Southern Access Extension Project

The Southern Access Extension Project involves the construction of a new crude oil pipeline extending the mainline from Flanagan to Patoka, Illinois. Project timing is being re-evaluated given changing customer product export preferences and as a result of delays in the regulatory process and the May 2008 denial by the Federal Energy Regulatory Commission (FERC) of the Company's October 2007 filing seeking a declaratory order (i.e. advance approval) of the tariff rate structure for the pipeline. Enbridge remains committed to meeting the shippers' need for transportation of crude oil from the Chicago area to the Patoka, Illinois hub and is working with customers to reposition the project in a manner that is commercially appropriate for the market and includes a tolling structure acceptable to the FERC.

Spearhead Pipeline Expansion

Construction on the Spearhead Pipeline Expansion began in September 2008. This expansion, to be effected through additional pumping stations, will increase system capacity from Flanagan, Illinois to Cushing, Oklahoma by 68,300 bpd to 193,300 bpd. The expansion is expected to cost US $0.1 billion and to be completed in the first half of 2009.

U.S. Gulf Coast Access

Based on feedback from shippers, Enbridge's focus will be on smaller scale alternatives involving low cost reconfiguration of existing facilities to accommodate U.S. Gulf Coast market access at volumes which are more closely aligned with supply growth.

United States Gulf Coast Joint Initiative The Company and BP are currently developing an initiative to deliver incremental volumes of Canadian heavy crude oil to U.S. Gulf Coast markets. The initiative would involve the reversal of the BP #1 pipeline system between Flanagan, Illinois and Cushing, Oklahoma as well as the use of existing pipelines and rights-of-way between Cushing and Houston, Texas. The scope of the project provides for a pipeline system with over 150,000 bpd of new capacity between Flanagan and Cushing and approximately 250,000 bpd of capacity between Cushing and Houston. BP is expected to be a significant shipper on the new system. The partners are currently finalizing commercial terms to present to additional shippers who have indicated interest in this alternative. The target in-service date for the pipeline system is late 2012.

Trailbreaker Project The Company initiated plans to provide access for western Canadian crude oil to refineries along the U.S. eastern seaboard and the U.S. Gulf Coast via the marine terminal at Portland, Maine. The Trailbreaker project contemplates the expansion and reversal of existing facilities to create a pipeline route to Portland. An open season process held by third-party owned Portland-Montreal Pipe Line did not receive sufficient commercial support for the reversal of one of its pipelines to transport crude oil from Montreal, Quebec to Portland. As a result, CAPP has exercised its right to withdraw support from the project at this time. Enbridge continues to engage in discussions with customers to determine timing and conditions for proceeding with this project.

Texas Access Pipeline The Company will continue to work with Exxon Mobil to develop the 450,000 bpd Texas Access Pipeline to provide the lowest cost large scale transportation solution to meet shippers' post-2012 requirements to providing U.S. Gulf Coast access for the volumes and on the schedule required by shippers.

Northern Gateway Project

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

The Company has secured funding from third party oil sands producers and Pacific Rim refiners to seek regulatory approval of the project.

The Company has requested the NEB and the Canadian Environmental Assessment Agency (CEAA) to resume their activities in respect of the environmental assessment process for the proposed project. CEAA will carry out consultations with potentially affected Aboriginal groups. The project is undergoing its own comprehensive public consultation program, which includes a series of community open houses designed to gather input, answer questions and build public awareness and understanding about the project.

The Company is committed to working with First Nations and Métis communities along the pipeline route to create opportunities for economic partnerships and to incorporate traditional knowledge into the planning and operations of the proposed project. See Aboriginal Relations.

Enbridge expects to file its regulatory application with the NEB in 2009. Subject to continued commercial support, regulatory and other approvals, the Company estimates that Northern Gateway could be in-service in the 2014 to 2015 time frame. The NEB posts public filings related to Northern Gateway on its website and Enbridge also maintains a Northern Gateway Project page on its own website. None of the information contained on, or connected to, either the NEB website or Enbridge's website is incorporated or otherwise part of this MD&A and we disclaim any intent to incorporate any of such information, either expressly or by reference.

5. Diluent Supply and Refined Products

With the Southern Lights diluent pipeline project on schedule for completion in 2010, the Company's strategy has shifted to expanding the number of physical connections to the pipeline to increase available

supply in the U.S. and available market outlets in Alberta. Selective development of refined products infrastructure will also be pursued.

Southern Lights Pipeline

When completed, the 180,000 bpd Southern Lights pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta. The project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline which runs 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 includes 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 will ultimately increase southbound light crude system capacity by approximately 45,000 bpd.

The Canadian portion of the Southern Lights Pipeline received NEB approval in the first quarter of 2008, enabling construction to commence on the LSr Pipeline and Line 2 modifications. Line 2 modifications, which allow Line 2 to operate at higher design rates, were nearing completion at the end of 2008. Due to a delay in NEB routing approvals, the planned in-service date for the LSr Pipeline has been delayed to early 2009.

In the U.S., construction of the LSr Pipeline and Line 2 modifications are complete. Diluent pipeline construction between Superior and Delavan, Wisconsin was completed in early 2008. Construction of the second segment of the diluent pipeline between Delavan, Wisconsin and Streator, Illinois was also substantially completed in 2008. Construction of the remaining U.S. line segments will commence in 2009. The diluent line is expected to be in service in late 2010.

The total expected project cost remains unchanged at US$1.7 billion (including AFUDC) for the U.S. segment and $0.5 billion (including AFUDC) for the Canadian segment.

6. Terminaling and Storage Infrastructure

In addition to regulated storage facilities, Enbridge owns and operates contracted storage adjacent to its pipeline systems. The Hardisty Terminal project will add an additional 7.5 million barrels of contract capacity. Liquids Pipelines continues to advance downstream terminaling projects at Flanagan, Patoka, Cushing and the U.S. Gulf Coast. Regulated storage initiatives will also be pursued at Edmonton, Superior, Griffith and Cromer.

Hardisty Terminal

Enbridge is building a crude oil terminal at Hardisty with a tankage capacity of 7.5 million barrels. Overall project construction was approximately 71% complete at the end of 2008. Tank capacities are expected to enter service in phases throughout 2009. Once complete, the $0.6 billion Hardisty Terminal will be one of the largest crude oil terminals in North America.

Stonefell Terminal – BA Energy

BA Energy Inc. proposed building a bitumen upgrader near Fort Saskatchewan, Alberta for which Enbridge had agreed to provide pipeline and terminaling services. In the second quarter of 2008, Enbridge was directed by BA Energy to stop work on this project and place the newly constructed tanks into standby. The Enbridge contractors have been demobilized and the project assets are in a storage mode. Project continuance and schedule are uncertain given BA Energy's filing for creditor protection. Enbridge's costs incurred to date, including a return on investment, have been fully reimbursed by BA Energy.

CAPITAL EXPENDITURES

In 2008, the Liquids Pipelines segment spent $164 million on capital maintenance and improvements compared with an expected $150 million. In 2009, the Company expects to spend approximately $160 million on capital maintenance and improvements.

Total expenditures for organic growth projects described above were $2.7 billion for 2008 compared with an expected $2.8 billion. For 2009, the Company expects to spend $2.9 billion for the organic growth projects. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under Risk Management.

Supply and Demand

The operation 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 and the price of natural gas used for steam production.

Demand depends, among other things, on weather, gasoline price and consumption, manufacturing, alternative energy sources and global supply disruptions.

Competition

Competition among 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 producers to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition could also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. One such competing project is currently under construction to initially serve markets at Wood River, Illinois and Cushing, Oklahoma, commencing in late 2009. This pipeline will have an initial capacity of 435,000 bpd and an ultimate capacity of 590,000 bpd. Commercial support has also been announced to construct additional ex-Alberta capacity of 500,000 bpd for an in-service date during 2012, which would be complemented by an extension of the system from Cushing, Oklahoma to Nederland, Texas. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls and multiple delivery and storage points.

Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system. 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 the Terrace Agreement 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 existing system but will on the Southern Access and Alberta Clipper expansions.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

Alberta Royalty Review

In September 2007, the Alberta Royalty Review Panel issued its recommendations to the government of the Province of Alberta calling for the adoption of measures to increase the Alberta government's share of revenues from oil sands development. A majority of the recommendations of the report were subsequently adopted by the Alberta government and became effective January 1, 2009. These measures may impact how oil sands developers evaluate future projects and this may reduce the level of future volumes expected to flow through the mainline system.

ITS Metrics

The ITS governing the Enbridge System measures the Company's performance in areas key to customer service. If the Company fails to meet the baseline targets set out in the ITS for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $30 million in 2009.

Potential Pressure Restrictions

The Company's Liquids Pipelines systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of the pipeline is indefinitely long; however, as the pipelines age the level of expenditures required for inspection and maintenance may increase. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs. Pressure restrictions may from time to time be established on other of 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. Pressure restrictions to date have not given rise to any loss of throughput. While the Enbridge System is volume-protected, EEP's Lakehead System and certain other pipelines would be adversely affected by pressure restrictions that reduce volumes transported. Additionally, on the Enbridge System ITS metrics penalties may apply if available capacity is reduced below baseline targets.

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. The NEB prescribes a benchmark multi-pipeline rate of return on common equity, which is 8.57% in 2009 (2008 – 8.71%). To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS, Terrace Agreement and agreements for projects currently under construction, which will govern the majority of the segment's assets.

GAS PIPELINES

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in Alliance Pipeline US, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising Offshore.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Alliance Pipeline US	**24.9**	27.7	29.7
Vector Pipeline	**14.2**	14.9	13.4
Enbridge Offshore Pipelines	**6.6**	21.8	18.1
Adjusted Earnings	**45.7**	64.4	61.2
Alliance Pipeline US – shipper claim settlement	**2.8**	–	–
Offshore – property insurance recovery from 2005 hurricanes, net of repair costs	**–**	5.3	–
Earnings	**48.5**	69.7	61.2

Adjusted earnings from Gas Pipelines were $45.7 million for the year ended December 31, 2008 compared with $64.4 million for the year ended December 31, 2007. The decrease in adjusted earnings was substantially due to continuing natural production declines and lost revenue and clean up costs related to Hurricanes Gustav and Ike in Offshore.

Adjusted earnings from Gas Pipelines were $64.4 million for the year ended December 31, 2007 compared with $61.2 million for the year ended December 31, 2006. Adjusted earnings improved as construction of the Neptune Pipelines (within Offshore) was completed and stand-by fees were earned starting in the fourth quarter of 2007.

Gas Pipelines earnings were impacted by the following non-operating adjusting items:

- In the first quarter of 2008, Alliance Pipeline US received $2.8 million in proceeds from the settlement of a claim against a former shipper which repudiated its capacity commitment.
- Earnings for the year ended December, 2007 included insurance proceeds of $5.3 million related to the replacement of damaged infrastructure as a result of the 2005 hurricanes.

Revenues for the year ended December 31, 2008 were $359.3 million compared with $321.3 for the year ended December 31, 2007. The increase in revenues is due to higher Alliance Pipeline US tolls, Vector expansion and revenues from Neptune within Offshore.

Revenues for the year ended December 31, 2007 were $321.3 million compared with $345.9 million for the year ended December 31, 2006. The decrease in revenues was substantially due to the effect of the weaker U.S. dollar.

ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and U.S. 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. The pipeline has firm service shipping contract capacity to deliver 1.325 billion cubic feet per day (bcf/d). EIF, described under Sponsored Investments, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with Aux Sable, a natural gas liquids extraction 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. Enbridge owns 42.7% of Aux Sable and its results are included under Gas Distribution and Services.

Results of Operations

Alliance Pipeline US adjusted earnings were $24.9 million for the year ended December 31, 2008 compared with $27.7 million for the year ended December 31, 2007. The decrease was primarily due to the weaker average U.S. dollar during 2008 and the depreciating ratebase.

The $2.0 million decrease in adjusted earnings between the years ended December 31, 2007 and 2006 was also primarily due to the weaker average U.S. dollar.

In the first quarter of 2008, Alliance Pipeline US received $2.8 million in proceeds from the settlement of a claim against a former shipper which repudiated its capacity commitment, resulting in increased earnings for the year ended December 31, 2008. Earnings for the years ended December 31, 2007 and 2006 equaled adjusted earnings.

Transportation Contracts

Alliance has long-term, take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010. 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 return on equity. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. 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 is expected to be recovered from shippers in subsequent years, beginning in 2009 for Alliance Pipeline US and 2012 for Alliance Pipeline Canada. As at December 31, 2008, $182.3 million (US$148.9 million) (2007 – $143.7 million; US$145.4 million) was recorded as deferred transportation revenue.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.2 bcf/d and is operating at or near capacity.

Vector Pipeline's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. Approximately 58% of the long haul capacity of Vector Pipeline is committed to long-term, 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service.

Results of Operations

Vector Pipeline earnings were $14.2 million for the year ended December 31, 2008 compared with $14.9 million for the year ended December 31, 2007. Earnings decreased as a result of increased taxes and by the weaker average U.S. dollar in 2008.

Vector Pipeline earnings were $14.9 million for the year ended December 31, 2007 compared with $13.4 million for the year ended December 31, 2006. Earnings improved, despite the stronger Canadian dollar, due to its late year expansion and lower operating costs in 2007.

STRATEGY

The Gas Pipelines strategy is developed based on the Company's forecast supply and demand for natural gas.

Supply and Demand for Natural Gas

The Chicago market is anticipated to enjoy robust supply as a result of increasing conventional production in the Rocky Mountains; expanding unconventional mid-continent production; and new supply from Gulf Coast liquefied natural gas (LNG) facilities. Surplus gas in Chicago may result in greater deliveries from this region to the Ontario market as traditional exports from Western Canada are expected to decline.

Further development of the oil sands projects in Alberta will increase the demand for natural gas as various extraction and upgrading processes require the use of natural gas. However, growth in natural gas demand in this sector may be tempered by alternative energy sources and delay or cancellation of oil sands projects.

Over time, the introduction of new supply from shale plays in northeast British Columbia and the U.S. Midcon region; increasing supply from the U.S. Rockies; LNG; and potential supply from the Alaska North Slope/Mackenzie Delta are expected to adequately supply the market and may provide opportunities for Enbridge to deliver this natural gas to markets.

Alliance Pipeline Recontracting Strategy

The Alliance Pipeline continues to be fully contracted on a firm service basis and is expected to run at or near full capacity until at least 2015 when existing long-term shipper contracts expire. Alliance Pipeline US is developing strategies to maximize its competitiveness, post-2015, in light of falling export production from Western Canada and the potential for surplus export pipeline capacity. Alliance is well placed to benefit from incremental unconventional volumes from shale plays in British Columbia and the northern gas development.

Rockies Alliance Pipeline

Alliance Pipeline US and Questar Overthrust Pipeline Company are jointly proposing a natural gas pipeline connecting the U.S. Rocky Mountain Region to the Chicago market hub. The proposed Rockies Alliance Pipeline (RAP) project is being developed in response to rapidly increasing supply from the U.S. Rockies region. RAP will enable producers, marketers and end-users to connect new gas supplies in the Greater Green River, Piceance, Uinta and Powder River basins with one of the largest and fastest growing markets in North America. The RAP project will take advantage of existing infrastructure with both Questar and Alliance to provide competitive transportation to key market areas.

Upon in-service of the proposed project, RAP will initially provide 1.3 bcf/d of transportation capacity which is expandable to 1.7 bcf/d with the addition of compression. Provided that sufficient commercial support for the project is obtained in 2009, the pipeline is expected to be in-service in 2013.

Vector Pipeline Expansion

The Vector pipeline is undertaking a 0.1 bcf/d expansion in 2009 with potential further expansion in 2010-2011.

BUSINESS RISKS

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

Supply and Demand

Advances in clean-coal technology and nuclear power as sources of power generation may reduce growth in natural gas demand over the longer term. However, demand is supported by declining U.S. traditional energy production, increasing need for clean burning natural gas and rising use of gas for power generation. 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 to 2015. 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.

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 the Alliance System. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US' competitive position.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded 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 for approximately 58% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term. 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 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 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.

Alberta Royalty Review

The Alberta Royalty Review as described under Liquids Pipelines is also applicable to both Vector Pipeline and Alliance Pipeline US.

ENBRIDGE OFFSHORE PIPELINES

Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines 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 1.7 bcf/d during 2008.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 in Offshore were $6.6 million compared with $21.8 million for the year ended December 31, 2007. Offshore adjusted earnings decreased as a result of continuing natural production declines as well as approximately $11.0 million in lost revenue and clean up costs related to Hurricanes Gustav and Ike. These decreases were partially offset by stand-by fees on the Neptune oil and gas pipelines which came into service in the fourth quarter of 2007, as well as contributions from Atlantis and Thunderhorse platform volumes. Also, adjusted earnings for the year ended December 31, 2008 included approximately $2.0 million (2007 – $6.0 million) from business interruption insurance proceeds related to lost revenue in 2005 and 2006 as a result of the 2005 hurricanes.

Offshore adjusted earnings for the year ended December 31, 2007 were $21.8 million compared with $18.1 million for the year ended December 31, 2006. In 2007, earnings reflected the impact of a weaker U.S. dollar, continuing repair and inspection costs and expected continuing natural production declines on deliveries to the pipelines in 2007. Start up issues experienced by producers on key production platforms, resulting from the effects of the extreme 2005 hurricane season, delayed new sources of volumes during the year; however, volumes from the Atlantis platform started contributing to earnings at the end of 2007. Adjusted earnings for the year ended December 31, 2007 also included approximately $6.0 million from business interruption insurance proceeds related to lost revenue in 2005 and 2006 as a result of the 2005 hurricanes which was offset by approximately $0.7 million in repair costs.

Earnings for the year ended December 31,2007 included non-operating insurance proceeds of $5.3 million related to the replacement of damaged infrastructure as a result of the 2005 hurricanes.

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 throughput volume 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 given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

Increasingly, and reflecting recent setbacks from hurricanes, certain transportation contracts are beginning to reflect hurricane allowances to cover increased operating and repair costs.

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.

Strategy

While Offshore's longer-term growth potential is attractive, the magnitude and timing of this growth will very much depend on the ability and willingness of upstream producers to develop new plays. Offshore will utilize its inherent advantages (existing infrastructure, operational expertise, reputation and integrity of personnel) to compete for new pipeline development opportunities. Projects under construction are described below.

Shenzi Project

Enbridge has completed constructing a natural gas lateral to connect the new deepwater Shenzi field to existing Gulf of Mexico pipelines. The US$65.0 million 11-mile (18-kilometre), 12-inch diameter gas pipeline has capacity of 0.1 bcf/d. In-service is currently scheduled for the second quarter of 2009, concurrent with producer first volumes. The Shenzi lateral will deliver natural gas through the Company's 22%-owned Cleopatra Pipeline, the 50%-owned Manta Ray Pipeline and the 50%-owned Nautilus Pipeline.

Thunder Horse Production Project

During the second quarter of 2008, the first well in the Thunder Horse Project was put in service ahead of the producer's revised schedule, with production continuing to ramp-up as new wells are brought on to production. This significant third party-owned project, which will deliver natural gas into Offshore's gathering systems, has experienced startup issues due to the severe 2005 hurricanes which delayed its original in-service schedule.

Business Risks

The risks identified below are specific to Enbridge Offshore Pipelines. General risks that affect the Company as a whole are described under Risk Management.

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 inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and refineries that may decrease throughput on Offshore systems.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage. However, costs have increased in the form of higher insurance premiums and deductibles as well as longer waiting periods for business interruption claims. It is expected the incidence and severity of windstorm occurrences, and the Company's direct experience in the Gulf of Mexico, will dictate future costs and coverage levels in this region.

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 production, as demonstrated with the newly constructed Neptune crude oil lateral. Given rates of decline, Offshore Pipelines typically have available capacity resulting in significant and aggressive 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 may be subject to challenge.

Other Risks

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

CAPITAL EXPENDITURES

The Company expects to spend approximately $70 million in 2009 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2008, the Company spent $136 million on capital expenditures in the Gas Pipelines segment which was consistent with expectations. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 27.0% ownership interest in EEP and a 41.9% voting interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge Energy Partners	**59.8**	47.3	36.5
Enbridge Income Fund	**41.1**	39.2	37.8
Adjusted Earnings	**100.9**	86.5	74.3
EEP – dilution gain on Class A unit issuance	**4.5**	11.8	–
EEP – unrealized derivative fair value gains/(losses)	**7.2**	(6.3)	6.5
EEP – gain on sale of Kansas Pipeline Company	**–**	3.0	–
EEP – impact of 2008 hurricanes and project write-offs	**(2.2)**	–	–
EIF – Alliance Canada shipper claim settlement	**1.3**	–	–
EIF – impact of tax rate changes	**–**	1.9	6.0
Earnings	**111.7**	96.9	86.8

Adjusted earnings from Sponsored Investments were $100.9 million for the year ended December 31, 2008 compared with $86.5 million in 2007. Adjusted earnings increased as a result of the strong performance at EEP and increased distributions from EIF.

Adjusted earnings from Sponsored Investments were $86.5 million for the year ended December 31, 2007 compared with $74.3 million in 2006. The increase in adjusted earnings was primarily a result of the strong performance at EEP.

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

- Earnings in 2008 and 2007 included EEP dilution gains because Enbridge did not fully participate in EEP's Class A unit offerings, decreasing Enbridge's ownership interest in EEP to 14.6%. In

December 2008, the Company purchased an additional US$500.0 million in Class A units increasing Enbridge ownership interest in EEP to 27.0%. Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.

- 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge's share is $0.8 million for the quarter and $1.6 million for the year-to-date, as well as the write-off of certain projects cancelled due to market conditions.
- Earnings from EIF for the year ended December 31, 2008 included proceeds of $1.3 million from the settlement of a claim against a former shipper on Alliance Canada which repudiated its capacity commitment.

Revenues from Sponsored Investments include only revenues from EIF as the Company accounts for its interest in EEP using the equity method. For the year ended December 31, 2008, revenues were $297.5 million compared with revenues of $270.3 million for the year ended December 31, 2007. The increase in revenue was a result of increased revenues from both higher tolls at Alliance Canada and higher allowance oil revenue from the Saskatchewan System.

For the year ended December 31, 2007, revenues were $270.3 million compared with revenues of $254.7 million for the year ended December 31, 2006. The $15.6 million increase in revenue was a result of increased tolls on the Alliance and Saskatchewan System as well as a full year contribution from the wind assets purchased in Q4-2006.

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the U.S., natural gas gathering and processing assets in Texas, the mid-continent crude oil system, various interstate and intrastate natural gas pipelines and a crude oil feeder pipeline in North Dakota.

Results of Operations

Adjusted earnings from EEP were $59.8 million for the year ended December 31, 2008, compared with $47.3 million for the year ended December 31, 2007. EEP adjusted earnings increased as a result of higher incentive income and increased earnings at EEP due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and additional revenue resulting from higher average crude oil prices associated with allowance oil. These increases were partially offset by increased operating and administrative costs and write downs of natural gas inventory to fair market value as a result of declines in the price of natural gas. Also, the Company's ownership interest in EEP increased to 27.0% in December 2008.

EEP earnings were favourably impacted by dilution gains because Enbridge did not fully participate in EEP's Class A unit offerings and by a change in the unrealized fair value on derivative financial instruments. Also, 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge's share is $1.6 million, as well as the write-off of certain projects cancelled due to market conditions.

Adjusted earnings from EEP were $47.3 million for the year ended December 31, 2007 compared with $36.5 million for the year ended December 31, 2006 despite the stronger Canadian dollar. The increase in adjusted earnings reflects Enbridge's larger average ownership interest in 2007 as well as higher incentive income, increased processing margins and higher volumes on principal natural gas and liquids systems that were partially offset by higher operating expenses.

Non-operating adjusting items impacted EEP earnings for fiscal 2007 and 2006 as follows:

- Dilution gains resulting from Enbridge not fully participating in Class A unit issuances.
- Unrealized derivative fair value gains and losses (losses in 2007 of $6.3 million; gains in 2006 of $6.5 million).
- Enbridge's $3.0 million share of the gain on the sale of Kansas Pipeline Company (KPC).

In the third quarter of 2006, EEP issued new Class C units. Enbridge participated in the offering and no dilution gains resulted. The Class C unit issuance increased Enbridge's ownership interest in EEP from 10.9% to 16.6%. Enbridge's average ownership interest in 2006 was 13.0%. In the second quarter of 2007, EEP issued partnership units. Because Enbridge did not fully participate in these offerings, dilution gains of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%. Enbridge's average ownership interest in 2007 was 15.5%. In March 2008, Enbridge did not participate in EEP's issuance of Class A units, resulting in a $4.5 million dilution gain and a decrease in ownership interest 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%

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, 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	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%

During 2006 EEP paid quarterly distributions of $0.925 per unit. In the first three quarters of 2007, EEP paid quarterly distributions of $0.925 per unit and effective November 2007, EEP increased quarterly distributions to $0.95 per unit. 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. Of the $75.7 million Enbridge recognized as earnings from EEP during 2008, 29% (2007 – 43%; 2006 – 37%) were general partner incentive earnings while 71% (2007 – 57%; 2006 – 63%) were Enbridge's limited partner share of EEP's earnings.

Strategy

Crude oil price volatility in 2008 has caused some crude oil producers to delay projects that were expected to commence over the next decade and this will cause EEP's expansion activities in and around EEP's Lakehead System to be more modest than experienced over the last several years. Significant liquidity tightening and volatility in the capital markets will necessitate a less aggressive capital program in EEP's natural gas business in the near term. During this period of volatility EEP will continue to focus primarily on development of the existing pipeline systems and those currently under construction. EEP will continue to evaluate strategic opportunities to further expand the service capabilities of its existing system.

In addition to the projects described under Liquids Pipelines, EEP is undertaking the following project:

North Dakota System Expansion

EEP is undertaking a further US$0.1 billion expansion of the North Dakota Pipeline System. The expansion is expected to increase system capacity from 110,000 bpd to 161,000 bpd and will consist of upgrades to existing pump stations, additional tankage as well as extensive use of drag reducing agents that are injected into the pipeline. The commercial structure for this expansion is a cost of service based surcharge that will be added to the existing transportation rates. Approval was received from the FERC in October 2008. The expansion is expected to be in-service in early 2010.

Business Risks

Financing Risk

EEP has made and expects to continue making substantial capital expenditures for the construction and development of crude oil and natural gas infrastructure. EEP intends to finance its future capital expenditures by utilizing cash from operations, borrowings under existing credit facilities and lastly from borrowings under the $500 million revolving credit agreement with Enbridge (see Liquidity and Capital Resources). EEP also expects to obtain permanent financing through the issuance of additional debt and equity securities, but may be unable to do so on attractive terms due to a number of factors including a lack of demand, poor economic conditions, unfavorable interest rates or its financial condition or credit rating at the time. In the event additional capital resources are unavailable; EEP may curtail construction and development activities, or be forced to sell some of its assets on an untimely or unfavorable basis in order to raise capital.

Supply and Demand

The profitability of EEP depends to a large 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.

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP 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 regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and NGLs. Historically, 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 Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of the Alliance System previously described in the Gas Pipelines segment. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in Southern Saskatchewan and Southwestern Manitoba connecting primarily with Enbridge's mainline pipeline to the United States.

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

Results of Operations

Adjusted earnings from EIF were $41.1 million for the year ended December 31, 2008, compared with the prior year of $39.2 million. EIF adjusted earnings for the year ended December 31, 2008 reflected a 7.5% increase in the monthly distributions received from the Fund, effective May 2008, as well as a one-time special distribution of $0.024 per unit. On November 3, 2008, the Fund announced that it will increase regular monthly distributions by 11.6% to $0.096 per unit, effective with the distribution to be

paid at the end of January 2009. This increase in adjusted earnings for the full year and in the fourth quarter was offset by higher tax on distributions received from EIF.

Adjusted earnings from EIF were $39.2 million for the year ended December 31, 2007, comparable with prior year adjusted earnings of $37.8 million.

In 2007, EIF recognized future taxes within entities that will become taxable in 2011 as a result of the enactment of Bill C-52, which is discussed under Tax Fairness Plan. This future tax increase was more than offset by the revaluation of future income tax obligations previously recorded as a result of tax rate reductions in the second and fourth quarters of 2007.

Tax Fairness Plan

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. The impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers. However, as enacted in its present form, the Tax Fairness Plan will serve to reduce, all other things being equal, cash available for distribution by EIF commencing in 2011.

Incentive and Management Fees

Enbridge receives a base annual management fee of $0.1 million for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2008, the Company received incentive fees of $5.3 million (2007 – $3.5 million, 2006 – $2.4 million). The Company is the primary beneficiary of EIF through a combination of the voting units and a non-voting preferred unit investment and as such EIF is consolidated under variable interest entity accounting rules.

Strategy

EIF will maximize the efficiency and profitability of its existing assets, pursue organic growth and expansion opportunities, invest in the expansion activities within its assets including the Saskatchewan System expansion and Alliance Canada receipt facilities expansion as well as three new waste heat power generation projects. The following project is being undertaken by EIF:

Saskatchewan System Capacity Expansion

EIF will begin construction in 2009 on Phase II of the Saskatchewan System Capacity Expansion. This expansion consists of four separate projects that will reduce capacity constraints at a variety of locations. Collectively, the projects will increase capacity across the system by approximately 129,000 bpd at an estimated cost of approximately $100 million. Completion of the four capacity expansion projects is expected by the third quarter of 2010.

Business Risks

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

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 and its expansion projects in order to meet its shippers' growing demand.

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.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable (a natural gas fractionation and extraction business) and the Company's Energy Services businesses.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge Gas Distribution	**123.3**	114.6	98.7
Noverco	**20.4**	18.6	18.7
Enbridge Gas New Brunswick (EGNB)	**14.7**	12.1	9.8
Other Gas Distribution	**7.6**	7.3	6.5
Energy Services	**16.8**	6.0	10.1
Aux Sable	**28.3**	10.6	25.8
Other	**(6.8)**	(0.3)	8.1
Adjusted earnings	**204.3**	168.9	177.7
EGD – colder/(warmer) than normal weather	**23.1**	14.2	(36.9)
EGD – provision for one-time charges	**(2.8)**	–	–
EGD/Noverco – impact of tax changes	**–**	26.8	28.9
Noverco – dilution gain	**–**	–	4.0
Energy Services – unrealized derivative fair value gains/(losses)	**22.6**	(2.4)	–
Energy Services – SemGroup and Lehman bankruptcies	**(5.7)**	–	–
Aux Sable – unrealized derivative fair value gains/(losses)	**54.5**	(28.1)	–
Other – gain on sale of investment in Inuvik Gas	**4.6**	–	–
Earnings	**300.6**	179.4	173.7

Adjusted earnings were $204.3 million for the year ended December 31, 2008 compared with $168.9 million for the year ended December 31, 2007. Earnings increased primarily due to customer growth and higher ancillary revenues at EGD, customer growth at EGNB and improved financial performance at Energy Services and Aux Sable.

Adjusted earnings were $168.9 million for the year ended December 31, 2007 compared with $177.7 million for the year ended December 31, 2006. Decreased earnings were due to lower contributions from Aux Sable and the Energy Services businesses, partially offset by customer growth and higher operating margins at EGD.

Gas Distribution and Services earnings were impacted by the following non-operating adjusting items:

- EGD's earnings included a $2.8 million provision for one-time charges to better align certain operating practices with its strategy under incentive regulation (IR).
- Energy Services earnings reflected unrealized fair value gains in 2008 and losses in 2007 on derivative instruments, resulting from forward risk management positions used to "lock-in" the profitability of forward physical transportation and storage transactions at Tidal Energy.
- Energy Services earnings for 2008 also included a $5.7 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. The full amount of all such receivables has been provided for; however, some potential for partial recovery exists.
- Aux Sable year-to-date earnings reflected unrealized fair value gains in 2008 and losses in 2007 on derivative financial instruments used to mitigate the uncertainty of the Company's 2009 share of the contingent upside sharing mechanism which allows Aux Sable to share in natural gas processing margins in excess of certain thresholds. Similar to Energy Services, these non-cash gains arose due to the revaluation of financial derivatives used to "lock in" the profitability of forward contracted prices.

Revenues for the year ended December 31, 2008 were $14,279.6 million compared with $10,217.9 million for the year ended December 31, 2007. The increase in revenues was due to higher average commodity prices in Energy Services and EGD as well as unrealized derivative gains on risk managed forward positions.

Revenues for the year ended December 31, 2007 were $10,217.9 million compared with $8,973.2 million for the year ended December 31, 2006. The increase in revenues was a result of a significant increase in volumes transacted by Energy Services and, to a lesser extent, an increase in commodity prices for those transactions.

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 1.9 million customers in central and eastern Ontario, southwestern Quebec 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.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 were $123.3 million compared with $114.6 million for the year ended December 31, 2007. EGD's increased adjusted earnings for 2008 reflect early success during its first of five years under IR, specifically through customer growth and higher ancillary revenues.

EGD's earnings included a $2.8 million provision for one-time charges to better align certain operating practices with the EGD's strategy under IR.

Adjusted earnings for the year ended December 31, 2007 were $114.6 million compared with $98.7 million for the year ended December 31, 2006. Adjusted earnings in 2007 increased compared with 2006 because of customer growth, higher rates from the increased rate base and a higher deemed equity component of the rate base for regulatory purposes.

Incentive Regulation

Improving the regulatory environment is a key strategic thrust to provide greater operational and organizational flexibility. In 2008, EGD moved to an IR methodology. Under IR, the distribution revenue requirement and therefore rates, are based on a formulaic approach, using 2007 as the starting point.

The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentive for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

2009 Rate Adjustment Application

On September 26, 2008, EGD filed an application with the OEB to adjust rates for 2009 pursuant to the 2008 approved IR formula. Subject to OEB approval, the rate adjustment would be effective January 1, 2009. A settlement agreement containing all as applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB on December 18, 2008.

2008 Rates

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

EGD received a fiscal 2008 final rate order from the OEB on May 15, 2008, approving the implementation of a change in rates effective July 1, 2008, which enabled EGD to recover the approved revenues retroactively to January 1, 2008. The final rate order also approved a change in customer billing

to increase the fixed charge portion and decrease the per unit volumetric charge, with no material annual earnings impact. The fixed charge portion will increase progressively over the IR term.

2007 Rates

EGD's rates for 2007 were set under a Cost of Service methodology that allowed the revenues to be set to recover EGD's forecast costs. Forecast costs included natural gas commodity and transportation, operation and maintenance, amortization, municipal taxes, income taxes and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under Cost of Service, it was the responsibility of EGD to demonstrate to the OEB the prudence of the costs it incurred or the activities it undertook.

Key elements of the OEB's 2007 rate decision, including issues previously settled and approved by the OEB, and a previous decision are summarized below:

Regulatory year	Approved 2007
Rate base *(millions of Canadian dollars)*	$3,745.7
Deemed common equity for regulatory purposes	36%
Rate of return on common equity	8.39%

For 2007, EGD was granted a 1% increase in the equity component of its deemed capital structure. The 36% deemed equity level is better reflective of changes in EGD's current business and financial risk relative to the earlier deemed equity level of 35%.

Strategy

EGD's vision is to become North America's leading energy distribution company. To achieve this vision, EGD has outlined the following strategic objectives:

- achieve top decile safety performance;
- enhance operational and financial governance effectiveness;
- deliver shareholder value;
- maintain a healthy and productive work environment; and
- enhance customer and stakeholder relationships.

One of EGD's major strategic initiatives is to continue to enhance the effectiveness of the business operations under IR, including rationalizing capital investment and increasing productivity. In addition, EGD will seek new growth opportunities, including growth in its core natural gas distribution business, investment in new infrastructure for power generation and fuel switching, development and delivery of energy efficiency programs and billing services for third parties, as well as the development of new natural gas storage space.

Customer Growth

Another major strategic initiative is enhancing customer growth. EGD added over 41,000 new customers during the year ended December 31, 2008 (over 43,000 in the year ended December 31, 2007). In addition to traditional gas distribution growth expected, new earnings growth opportunities include investment in new infrastructure for power generation, fuel switching, implementation of turboexpanders on the natural gas distribution system, development and delivery of energy efficiency programs and billing services for third parties, as well as development of new natural gas storage space.

Storage Project

The Company provides storage services to wholesale storage market participants. In 2008, the Company provided approximately 3 million gigajoules of high deliverability storage capacity to these customers. Management continues to monitor the storage market and expects to develop new storage capacity when it is economically appropriate.

Customer Care and Customer Information System

In April 2007, EGD entered into new five-year customer care services contracts with third-party service providers for meter reading, billing, billing administration, call handling and collections. The total cost of the contracts is approximately $274 million over the five-year term. EGD is also working towards implementing a new Customer Information System, which will replace the legacy system by July 2009 and at an estimated cost of $119 million, in order to meet regulatory requirements and to meet the need for a more robust and technologically up-to-date system.

The OEB has approved a six-year rate recovery arrangement for customer care services and a 10 year recovery of the $119 million to be invested in the new CIS.

Capital Expenditures

EGD's capital expenditures in 2008 were $411 million and are expected to be $389 million in 2009 as EGD completes laterals for new power generating facilities, and builds its CIS system discussed above.

Legal Proceedings

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 on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. The appeal is scheduled to be heard by the Court during November 2009. The maximum possible fine upon conviction would not result in any material financial impact on EGD.

EGD has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on EGD. A Coroner's Inquest in connection with the explosion is also possible.

Harper Gardens Incident

On February 14, 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A natural gas contractor working in the home at the time of the explosion was seriously injured. Several public authorities commenced investigations in connection with the incident. The Company has also been named as a defendant in civil actions related to the incident, but does not expect these actions to result in any material financial impact.

GST Overpayment

In December 2007, EGD discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment is approximately $40 million. EGD expects that it will recover the overpayment from the CRA during 2009.

Business Risks

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

Regulatory Risk

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

The Settlement allows certain categories of expense, added at Cost of Service base amounts, and uncontrollable external factors in the IR formula, 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 end the IR plan and return to cost of service if there are

significant 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.

EGD does not profit from the sale of the natural gas commodity 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 commodity cost differential. EGD has a quarterly rate adjustment mechanism in place for the natural gas commodity. This allows for the quarterly adjustment of rates to reflect changes in natural gas commodity prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, EGD's ability to collect its total revenue requirement depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts will be 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 the growth of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. In recent years, earnings have been impacted given the unusual pattern of weather during the year.

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 to partially mitigate the impact of higher natural gas commodity prices further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 79% (2007 – 78%) 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 the return on equity 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 use of appropriate forecasting models and through the average use true-up variance account that was established under the IR Settlement Agreement. 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 is still at distribution volume risk for contract customers.

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 publicly traded gas distribution company operating in the province of Quebec and the state of Vermont.

Results of Operations

Noverco adjusted earnings were $20.4 million for the year ended December 31, 2008, comparable to $18.6 million for the year ended December 31, 2007 and $18.7 million for the year ended December 31, 2006.

In 2006, earnings were impacted by a non-operating adjusting item of a $4.0 million as a result of the recognition of a dilution gain from a Gaz Metro unit issuance in which Noverco did not participate.

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%.

ENBRIDGE GAS NEW BRUNSWICK

The Company owns 70.9% of, and operates, Enbridge Gas New Brunswick, which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 9,400 customers. Approximately 725 kilometres (450 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

Results of Operations

EGNB earnings were $14.7 million for the year ended December 31, 2008 compared with $12.1 million for the year ended December 31, 2007 and $9.8 million for the year ended December 31, 2006. Earnings were higher in 2008 and 2007 as a result of franchise customer growth.

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 difference between distribution revenues and the cost of service during the development period for recovery in future rates. This recovery period is expected to start in 2010 and end no sooner than December 31, 2040. On December 31, 2008, the regulatory deferral asset was $132.7 million (2007 – $117.7 million).

ENERGY SERVICES

Energy Services includes Gas Services and Tidal Energy, the Company's energy marketing businesses. Gas Services markets natural gas to optimize Enbridge's commitments on the Alliance and Vector Pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to transportation capacity. Capacity commitments as of December 31, 2008 were 32.7 mmcf/d on the Alliance Pipeline (2.5% of total capacity) and 144 mmcf/d on Vector Pipeline (12.0% of total capacity). Capacity commitments as of December 31, 2007 were 32.2 mmcf/d on the Alliance Pipeline (2.0% of total capacity) and 162.1 mmcf/d on Vector Pipeline (16.4% of total capacity).

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance Pipeline, and between Chicago and Dawn, for Vector Pipeline. To the extent the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing risk management pricing options. Tidal Energy's business involves buying, selling and storing large quantities of crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities, physical receipt or delivery shortfalls can create modest commodity exposures. Any open positions created from this physical business are tightly monitored and must comply with the Company's formal risk management policies.

Results of Operations

Adjusted earnings from Energy Services were $16.8 million for the year ended December 31, 2008 compared with $6.0 million for the year ended December 31, 2007. Energy Services adjusted earnings

increased due to higher margins captured on storage and transportation contracts as well as increased transportation and storage volumes in Tidal Energy.

Energy Services earnings were impacted by several non-operating adjusting items; unrealized fair value gains on derivative instruments, resulting from forward risk management positions used to "lock-in" the profitability of forward physical transportation and storage transactions at Tidal Energy, and a $5.7 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. The full amount of all such receivables has been provided for and some potential for partial recovery exists.

Adjusted earnings from Energy Services were $6.0 million for the year ended December 31, 2007 compared with $10.1 million for the year ended December 31, 2006. The decrease in adjusted earnings was due to outstanding storage transactions in Tidal Energy that were negatively impacted by rising crude oil prices. Tidal Energy buys crude oil, stores it and sells it forward at a higher price, locking in a profit on the transaction. However, during the life of the transaction, Tidal Energy may hold the oil held in storage and use it to satisfy a new forward sale at an additional deferred profit. Tidal Energy then purchases oil at spot prices to satisfy the original sale transaction. As a result, losses will be recognized in periods of rising oil prices and profitability will be deferred until the original transaction settles.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago. Aux Sable owns and operates a plant at the terminus of the Alliance System. The plant extracts NGLs from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGLs, or lower heat content, and to take advantage of positive commodity price spreads.

Aux Sable has an agreement with BP Products North America Inc. to sell its NGLs production to BP. In return, 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 supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, commencing January 1, 2006 and may be extended by mutual agreement for 10-year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, although Aux Sable has the right to reduce such losses to avoid termination.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 were $28.3 million compared with $10.6 million for the year ended December 31, 2007. Aux Sable adjusted earnings increased due to strong fractionation margins and enhanced plant performance, in addition to favourable risk management positions, which enabled the Company to recognize earnings from the upside sharing mechanism.

Aux Sable year-to-date earnings reflected unrealized fair value gains on derivative financial instruments used to risk manage the Company's 2009 share of the contingent upside sharing mechanism, which allows Aux Sable to share in natural gas processing margins in excess of certain thresholds. Similar to Energy Services, these non-cash, non-operating gains arose due to the revaluation of financial derivatives used to "lock in" the profitability of forward contracted prices.

Adjusted earnings for the year ended December 31, 2007 were $10.6 million compared with earnings of $25.8 million for the year ended December 31, 2006. The decrease was due to lower fractionation spreads in 2007 compared with 2006 as well as the weaker U.S. dollar.

Aux Sable's 2007 reported earnings included $28.1 million of unrealized derivative fair value losses related to the Company's share of 2008 contingent upside sharing revenue.

OTHER

The adjusted operating loss in Other was $6.8 million in 2008 compared with $0.3 million in 2007. Losses in Other for the year ended December 31, 2008 primarily reflected lower earnings from CustomerWorks which resulted from the April 2007 transition of customer care services related to EGD to a third-party service provider pursuant to an OEB recommendation.

Adjusted operating loss in Other was $0.3 million in 2007 compared with adjusted earnings of $8.1 million in 2006. Lower earnings in 2007 were primarily due to the change at Customer Works.

Strategy

Other Natural Gas Distribution Strategies

Enbridge intends to pursue natural gas business development opportunities complementary to the existing gas distribution and services businesses through:

- developing LNG regasification projects and related pipeline infrastructure;
- pursuing marketing and storage opportunities that optimize existing assets; and
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. The approach is to slowly build this business and utilize partners to share development risks.

Further to this strategy, Enbridge is developing a number of projects, which are described below.

Rabaska LNG Facility

In the second quarter of 2008, the Rabaska partners signed a Letter of Intent with Gazprom Marketing & Trading USA, Inc. (GMTUSA) regarding supply for the proposed Rabaska LNG regasification terminal. The Letter of Intent outlines the major terms under which GMTUSA will become an equity partner in the proposed Rabaska LNG project and will contract for 100% of the Rabaska terminal's capacity. The Rabaska LNG facility has all major authorizations, including project and land use approvals from the province of Quebec in October 2007 and federal government approvals in March 2008. Pending commercial advancement of GMTUSA's upstream development, the project is schedule to be in service in 2013 or 2014.

NetThruPut

In 2007, the Company and its partner in NetThruPut (NTP) entered into an agreement with the TSX Group granting the TSX Group the option to purchase NTP, an internet-based crude oil trading and clearing platform. Proceeds of $9.5 million were received from the sale of the option. The option may be exercised at a time after March 15, 2009 for a price of approximately $60 million. The agreement also provides the Company and its partner in NTP an option to sell NTP under the same terms to the TSX Group. The Company has a 52% ownership interest in NTP.

CAPITAL EXPENDITURES

Capital expenditures in Gas Distribution and Services, excluding EGD, were $73 million in 2008 (2007 – $86 million). Capital expenditures for 2009 are expected to be $93 million.

INTERNATIONAL

International includes the Company's investment in, and management of, Oleoducto Central S.A. (OCENSA), a crude oil pipeline in Colombia, as well as earnings from the Company's interest in Compañía Logística de Hidrocarburos CLH, S.A., Spain's largest refined products transportation and storage business, prior to its sale. Other includes administration and business development.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
OCENSA/CITCol	**32.7**	32.9	33.9
CLH	**24.7**	60.4	54.5
Other	**(5.3)**	(3.4)	(5.2)
Adjusted Earnings	**52.1**	89.9	83.2
CLH – gain on sale of investment	**556.1**	–	–
CLH – gain on land sale	**–**	5.2	–
Earnings	**608.2**	95.1	83.2

Adjusted earnings for the year ended December 31, 2008 were $52.1 million compared with $89.9 million for the year ended December 31, 2007. International's adjusted earnings decreased for the year ended December 31, 2008 as a result of the sale of CLH on June 17, 2008, which also resulted in a non-operating gain on disposal of $556.1 million increasing 2008 earnings to $608.2 million compared with $95.1 million in 2007.

Adjusted earnings for the year ended December 31, 2007 were $89.9 million compared with $83.2 million for the year ended December 31, 2006. The increase in adjusted earnings was due to stronger operating earnings in CLH as a result of higher transported volumes, an increase in operating revenues from complimentary businesses, lower income taxes as a result of a tax rate reduction in Spain and lower business development costs in Other.

Earnings in 2007 included a $5.2 million gain on the sale of land within CLH.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, an investment on which the Company earns a fixed return. OCENSA is one of two main crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages the pipeline and earns a fee for this service, which includes incentives for operating performance. In 2007, OCENSA made the final payments with respect to its original US$1.6 billion project debt financing. With no further debt servicing obligations OCENSA may opt to begin returning the Company's initial equity capital starting in 2009, in accordance with the terms of the project agreements.

CLH

On June 17, 2008, the Company sold its 25% equity interest in CLH. Proceeds from the disposal of the CLH investment were applied toward funding the Company's North American growth projects.

STRATEGY

The Company's strategy internationally has always been patient and opportunistic. Two staggered investments in Colombia and Spain over the course of 13 years, and the recent profitable sale of the Spanish investment, demonstrate this approach. While the International portfolio has recently decreased in size, the Company continues to view this business segment as attractive and it could potentially once again become a meaningful portion of the Company. International investments provide unique diversification and potentially premium risk-adjusted returns, provided they meet the Company's stringent investment criteria.

BUSINESS RISKS

The International business is subject to risks related to political and economic instability, currency volatility, market and supply volatility, government regulations, foreign investment rules, security of assets and environmental considerations. The Company assesses and monitors international regions and specific countries on an ongoing basis for changes in these risks. Risks are mitigated by a combination of Enbridge's governance involvement, contractual arrangements, influence in operation of the assets, regular analysis of country risk as well as foreign currency hedging and insurance programs.

Competition

The Company's current strategic focus may constrain the level of resources and attention focused on opportunities in the broader international market. International has mitigated the risk by monitoring and investigating international investment opportunities.

CORPORATE

Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments. This segment also includes new platforms currently being pursued by the Company including renewable energy (wind and solar), CO2 transportation and sequestration and Pathfinding initiatives. Pathfinding initiatives include pursuing investment in smaller start-up entities where that investment will enable the development of promising new technologies that complement the Company's core operations.

(millions of Canadian dollars)	**2008**	2007	2006
Adjusted Corporate Costs	**(57.8)**	(59.2)	(77.7)
Gain on sale of corporate aircraft	**4.9**	–	–
U.S. pipeline tax decision	**(32.2)**	–	–
Unrealized derivative fair value gains	**26.2**	–	–
Asset impairment loss	**(17.3)**	–	–
Impact of tax changes	**–**	31.1	14.0
Costs	**(76.2)**	(28.1)	(63.7)

Corporate costs before adjusting items were $57.8 million for the year ended December 31, 2008, comparable with $59.2 million for the year ended December 31, 2007.

2008 corporate costs were impacted by the following non-operating adjusting items:

- A $4.9 million gain on the sale of a corporate aircraft.
- An unfavourable court decision related to the tax basis of previously owned U.S. pipeline assets which resulted in the recognition of a $32.2 million income tax expense.
- Unrealized fair value gain on derivative financial instruments, resulting from forward risk management positions to minimize the volatility of future U.S. dollar earnings across the Company.
- Asset impairment loss related to the write-off of goodwill related to the Company's Ontario wind power assets as well as a write-down of the Company's investment in NSolv, a technology development venture.

Corporate costs before adjusting items were $59.2 million for the year ended December 31, 2007, compared with $77.7 million in 2006. Corporate costs decreased due to lower interest expense resulting from decreased average debt balances throughout 2007 as a result of the equity issuance in the first quarter. As well, expenditures on corporate development activity decreased because of the Company's focus on organic growth. Corporate costs were impacted by the non-operating adjusting item of favorable legislated tax changes in both years.

STRATEGY

In the longer term, developing new business platforms will be important to maintaining growth and diversification within the Company. New platforms currently being pursued include renewable energy

(wind and solar), CO2 transportation and sequestration and Pathfinding initiatives. The Company is currently undertaking the following projects:

Ontario Wind Project

Construction of the 190-megawatt Enbridge Ontario Wind Power Project, located in the Municipality of Kincardine on the Eastern shore of Lake Huron in Ontario, was completed in the fourth quarter of 2008. Although turbines were fully available for operation at the end of 2008, staging of turbine operations was implemented to ensure safe and reliable operations for the wind project. As of December 31, 2008, 65 of the 115 wind turbines (56.5%) were operating and reliably delivering power to the grid. The remaining 50 turbines will be phased into service with all turbines targeted to deliver power to the grid by early February 2009. The final capital cost of the project is estimated at $481 million.

Alberta Saline Aquifer Project

The 38-member Alberta Saline Aquifer Project (ASAP) is on track to complete Phase I in Spring 2009. Phase I has identified specific reservoir locations that offer the potential for long term carbon dioxide sequestration and has developed a preliminary design and cost estimate for a carbon dioxide sequestration pilot. Following receipt of regulatory approvals, the ASAP team anticipates that it will begin Phase II, constructing the pilot project, including drilling of the injection and monitoring wells in 2009, with injections of carbon dioxide beginning in 2010. Phase III will involve expanding the pilot project to a large-scale, long-term commercial operation. ASAP, spearheaded by Enbridge, is the largest project of its kind in North America and will play a major role in advancing industry and government's knowledge of carbon dioxide sequestration.

Hybrid Fuel Cell Power Plant

In October 2008, the Company and FuelCell Energy Inc. announced the opening of the world's first hybrid fuel cell power plant. The plant, which will produce 2.2 megawatts of environmentally preferred, ultra-clean electricity, or enough power for approximately 1,700 residences, is also the first multi-megawatt commercial fuel cell to operate in Canada. Support for this $10 million project was provided by both the Canadian and Ontario Governments. The Company, as the exclusive distributor of the hybrid fuel cell technology, will be promoting the technology to other natural gas distribution companies throughout North America.

CAPITAL EXPENDITURES

Capital expenditures in Corporate were $117 million in 2008 (2007 – $159 million). Capital expenditures for 2009 are expected to be $80 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company will utilize cash from operations and the issuance of commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures and pay common share dividends throughout 2009. At December 31, 2008, the Company had $6.5 billion (2007 – $5.6 billion) of committed credit facilities excluding the Southern Lights project financing described below, of which $3.4 billion was drawn or used to backstop commercial paper. The Company has provided EEP with a revolving credit agreement for up to US$0.5 billion resulting in net available liquidity at December 31, 2008 for the Company of $3.0 billion, inclusive of cash and cash equivalents of

$0.5 billion. The following table provides details of the company's credit facilities at December 31, 2008.

	Expiry Dates	Total Facilities	Credit Facility Draws	Commercial Paper Backstop	Available
(millions of Canadian dollars)					
Liquids Pipelines	2010 - 2011	1,300.0	525.5	–	774.5
Gas Distribution and Services	2009 - 2010	1,014.7	11.1	874.5	129.1
Corporate [1]	2010 - 2013	4,185.8	962.3	1,075.1	2,148.4
		6,500.5	1,498.9	1,949.6	3,052.0
Southern Lights project financing [2]	2014	2,028.1	1,358.9	–	669.2
Credit facilities		8,528.6	2,857.8	1,949.6	3,721.2

1 Total facilities exclusive of $49.0 million commitment of Lehman Brothers Bank given the bankruptcy filing of its parent in September 2008.

2 Total facilities inclusive of $140.2 million which is available if certain conditions related to the project are met.

In January 2009, a credit facility established in December 2008, was increased by $0.2 billion to $0.5 billion as a result of new lender commitments, providing additional liquidity. The Company will look to access the capital markets for long-term financing as projects approach the in service date and to manage overall liquidity. The Company was successful in accessing $0.5 billion from the debt capital markets in the fourth quarter of 2008, as noted below in Financing Activities.

During 2008, the Company established $0.4 billion and US$1.3 billion in project financing that is non-recourse to the Company, for the Canadian and U.S. components of the Southern Lights project. These facilities are sufficient to fund the debt component of the Southern Lights financing and comprise construction, cost overrun and letter of credit facilities that mature in 2014, which is four years beyond the expected completion date of the project. At December 31, 2008, $0.3 billion and US$0.9 billion were drawn under the project financing facilities.

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.

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, 2008, including short-term borrowings but excluding non-recourse debt and project financing was 60.7%, compared with 62.7% at the end of 2007. Including all debt, the capitalization ratio was 66.6% compared with 66.5% at the end of 2007.

The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. At December 31, 2008, there were $474.2 million of short-term investments intended to enhance access to short-term liquidity given the recent market turbulence. Short-term investments were $87.8 million in 2007 and $66.8 million in 2006.

Excluding current maturities of long-term debt, the Company has a positive working capital position, consistent with December 31, 2007.

(millions of Canadian dollars)	**2008**	2007
Cash and cash equivalents	**541.7**	166.7
Accounts receivable and other	**2,322.5**	2,388.7
Inventory	**844.7**	709.4
Short-term borrowings	**(874.6)**	(545.6)
Accounts payable and other	**(2,411.5)**	(2,213.8)
Interest payable	**(101.9)**	(89.1)
Working capital	**320.9**	416.3

Changes in commodity prices impact accounts receivable, inventory and accounts payable at Tidal Energy and EGD.

OPERATING ACTIVITIES

Cash from operating activities increased to $1,387.7 million for the year ended December 31, 2008 from $1,351.6 million for the year ended December 31, 2007 and $1,315.3 million for the year ended December 31, 2006.

(millions of Canadian dollars)	**2008**	2007	2006
Earnings net of non-cash items	**1,398.0**	1,358.0	1,191.6
Changes in operating assets and liabilities	**(10.3)**	(6.4)	123.7
Cash Provided by Operating Activities	**1,387.7**	1,351.6	1,315.3

Cash provided by earnings net of non-cash items, was $1,398.0 million for the year ended December 31, 2008, compared with $1,358.0 million and $1,191.6 million for 2007 and 2006, respectively. The increased earnings from operating activities in 2008 and 2007 resulted primarily from higher earnings at EGD. Cash from operating activities are stable and predictable for the Company given the regulated nature of the assets.

There are no material restrictions on the Company's cash with the exception of proportionately consolidated joint venture cash of $73.6 million, which cannot be accessed until distributed to the Company.

Changes in operating assets and liabilities were $130.1 million lower in 2007 compared with 2006. This decrease primarily resulted from increased accounts receivable at EGD at December 31, 2007 due to the relatively colder weather experienced during the final billing periods of the year.

INVESTING ACTIVITIES

In 2008, cash used for investing activities was $2,852.9 million compared with $2,228.8 million in 2007, an increase of $624.1 million. In 2008, the Company had increased capital expenditures primarily due to growth projects such as Southern Lights, Alberta Clipper and Line 4 as well as core maintenance expenditures incurred primarily at EGD and Enbridge System. In November 2008, the Company increased its investment in EEP by subscribing for 16.3 million Class A common units for US$500.0 million. These expenditures were partially offset by the proceeds from the sale of Enbridge's investment in CLH in 2008.

Cash used for investing activities for the year ended December 31, 2007 was $2,228.8 million compared with $1,597.6 million in 2006 as a result of increased capital expenditures primarily due to growth projects such as Southern Lights, Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge System.

FINANCING ACTIVITIES

In 2008, the Company generated $1,840.2 million through financing activities compared with $904.2 million and $268.1 million in 2007 and 2006, respectively.

Short-term borrowings at EGD are used primarily to finance working capital, including inventory.

In 2008, the Company added new credit facilities of $1.3 billion. Increased funding through commercial paper issuances and draws under committed credit facilities was required in 2008 to fund capital expenditures and the Company's investment in EEP. In 2007, the Company expanded its available liquidity through credit facility expansions and additions totaling $1.9 billion.

In the last quarter of 2008, the Company issued $0.5 billion of long-term notes. Specifically, EGD issued a $0.2 billion five-year term note and Enbridge Pipelines Inc. closed a $0.3 billion ten-year term note. The Company had total note maturities of $0.6 billion, of which $0.3 billion was repaid by EGD. Financing activities in 2007 included the issuance of US$1.1 billion of term notes in the U.S. market and $0.2 billion of term notes in the Canadian market to offset term note maturities of $0.6 billion. During 2006, the Company issued $1.1 billion and repaid $400 million of term notes.

During 2008, the Company borrowed $0.3 billion and US$0.9 billion in project financing that is non-recourse to the Company, for the Canadian and U.S. components of the Southern Lights project. This financing resulted in the full repayment and cancellation of a US$0.5 billion facility established in 2007 to fund project costs directly related to the Southern Lights Project on an interim basis, which had been guaranteed by the Company.

Dividends paid on common shares decreased in 2008 due to the increased use of the Company's dividend reinvestment plan, which provided a $130.1 million increase in equity funding. Dividends paid on common shares increased in 2007 due to an increased number of common shares outstanding and a higher dividend rate.

Equity Issuance

On February 2, 2007, Enbridge closed the issuance to the public of 13.5 million common shares for $38.75 per share and issued 1.5 million common shares to Noverco for $38.75 per share, which maintained Noverco's ownership interest in Enbridge at approximately 9.5%. Net proceeds from both offerings totaled $566.4 million.

Preferred Securities

The Company redeemed its $200 million, 7.8% Preferred Securities on February 15, 2007.

EXPECTED CAPITAL EXPENDITURES

The numerous organic growth projects and other growth initiatives described in the business unit sections will require capital funding. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3.7 billion during 2009 on capital projects and maintenance. 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.

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. For certain construction projects, financing costs are eligible for reimbursement through tolls. 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 issue of replacement debt.

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

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt [1]	10,673.7	533.1	750.0	450.0	8,940.6
Non-recourse long-term debt [1]	1,617.2	176.2	259.7	218.3	963.0
Capital and operating leases	180.0	15.1	32.3	35.2	97.4
Long term contracts [2, 3]	3,345.4	2,058.8	616.4	407.5	262.7
Pension obligations [4]	48.4	48.4	–	–	–
Total Contractual Obligations	15,864.7	2,831.6	1,658.4	1,111.0	10,263.7

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

2 Approximately $1,579.0 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects. Changes to the planned funding requirements, including cancelation, are dependent on changes to the related projects.

3 Contracts totaling $35 million are within proportionately consolidated joint venture entities and contracts totaling $230.3 million are between the Company and proportionately consolidated joint venture entities.

4 Assumes no discretionary payments will be made into the pension plans in 2009. Contributions subsequent to 2009 will be made in accordance with the independent actuarial valuations required as of December 31, 2009. Contributions, including discretionary payments, may be larger than current amounts pending future asset performance.

SENSITIVITY ANALYSIS

The Company's earnings will fluctuate with changes in certain market prices, volumetric throughput on certain assets, with weather and other factors.

MARKET PRICES

Earnings at Risk (EaR) 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, with a 97.5% level of confidence, the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period. The Company's policy is to target a maximum EaR of 5% of 1 year forecasted earnings. On December 31, 2008, the Company's EaR was 2.5% (2007 – 2.8%) of 1 year forecasted adjusted earnings.

The following table shows the EaR from changes to different types of market price risk. These EaR numbers are based on business conditions and hedging programs as of December 31, 2008 and may not be applicable to other periods.

Risk	EaR
Commodity	$13.7 million
Foreign Exchange	$3.6 million
Interest Rate	$3.2 million

VOLUMETRIC THROUGHPUT

Transportation volumetric risks are managed through tariff agreements. Most of the Company's tariff agreements provide for take-or-pay or throughput insensitivity.

WEATHER

Weather is a significant driver of delivery volumes at EGD, given that a significant portion of EGD's customers use natural gas for space heating. Weather, measured in terms of degree day deficiency, normally directly impacts EGD's earnings as noted below. Degree-day is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	17 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.4 million (after-tax)

In recent years weather has impacted earnings by a larger magnitude than the above sensitivities would suggest. This results from the unusual pattern of distribution of degree days during the year and their relative effectiveness. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Weather risk is also present in Enbridge Offshore Pipelines; hurricanes have impacted earnings by $11 million in 2008.

RISK MANAGEMENT

The Company's business activities are subject to execution, financing, market price, credit and operating risks, among others. The Company has formal risk management policies, processes and systems designed to mitigate these risks.

The current economic conditions have not caused the Company to change any risk management practices. The existing philosophy and framework was designed to be applied consistently in all market conditions. The Company continues to closely measure and monitor risks using best practice methodologies and manage exposures within the risk constraints of approved policies.

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, delays in government approvals, cost escalations, construction delays and shortages (collectively Execution Risk). The Company's significant 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, 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 clearly defined management and governance structure for all major projects. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements. The Company's emphasis on corporate social responsibility promotes generally positive relationships with landowners, aboriginal groups and governments. Cost tracking and centralized purchasing is used on all major projects. 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. In early 2008, the Company made changes in its senior management team structure which further emphasize successful project execution.

FINANCING RISK

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

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

MARKET PRICE RISK

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively Market Price Risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Board of Directors approved Market Price Risk Policy to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its

businesses will exceed a defined tolerance. The primary Market Price Risk metric used to monitor risk and establish limits within that policy is EaR, as described above under Sensitivity Analysis.

The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed and the financial derivative hedging programs implemented.

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar denominated investments, where carrying values, cashflows and earnings are subject to foreign exchange rate variability. The Company has implemented a policy whereby it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. Under this policy, the Company has substantially hedged this exposure. The Company may also hedge shorter term anticipated foreign currency denominated capital expenditures. The earnings exposure from the foreign exchange positions is managed within the overall consolidated EaR limits of the Company.

Interest Rate Risk

The Company's cashflows and earnings are exposed to interest rate fluctuations due to the regular repricing of its variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company 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. The Company is also exposed to fluctuations in longer term interest rates ahead of anticipated fixed rate debt issuances. Many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls. The Company may enter into interest rate derivatives to hedge a portion of the interest cost of these future debt issues. The earnings exposure from the interest rate portfolio is managed within the overall consolidated EaR limits of the Company. As well, for certain construction projects, financing costs are eligible for reimbursement through tolls.

Information about the debt portfolio is included in Notes 15 and 16 of the 2008 Annual Consolidated Financial Statements.

Commodity Price Risk

The Company's cashflows and earnings 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 affiliates. 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 earnings exposure from the commodity positions is managed within business unit EaR sub-limits, as well as within the overall consolidated EaR limits of the Company.

Fair Values of Derivative Instruments

Information about the financial instruments (including derivatives) outstanding at year end is included in Note 22 of the 2008 Annual Consolidated Financial Statements.

CREDIT RISK

Credit risk arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. Certain large volume customers are exposed in times of economic uncertainty. In these cases, the Company has secured credit enhancement to assist in mitigating credit exposure.

Entering into derivative financial instruments can also give rise 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. Overall credit exposure limits have been set in the Board of Directors approved Credit Policy.

The Company minimizes credit risk by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. During 2008, the Company rebalanced its exposure to certain financial counterparties through the discontinuance of certain hedges. 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 2008, notwithstanding the above mitigants, severe market conditions caused two counterparties to default resulting in the Company's first meaningful credit losses. These losses, included in Gas Distribution and Services earnings, totaled $5.7 million.

OPERATING RISKS

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. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks.

Regulation

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers.

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 could experience incidents, malfunctions or other unplanned events that could 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 greenhouse

gas 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. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to greenhouse gas 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.

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 aboriginal groups, landowners and other 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 CSR program also reports on the Company's responsiveness to environmental and community issues. Please see the annual CSR report for further details regarding the CSR program.

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 [1]. While good business practice generally, and a Crown duty in some cases, consultation has the potential to delay regulatory approval processes and construction, which may affect project economics.

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 sustainable benefits from our 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.

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 and is focused on recruiting efforts while enhancing employee engagement. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human capital is balanced between hiring full-time employees and expanding the contractor workforce, particularly in the Major Projects' department.

1 See generally, *R. v. Sparrow*, [1990] 1 S.C.R. 1075, *R. v. Badger*, [1996] 1 S.C.R. 771 and *Delgamuukw v. B.C.*, [1997] 3 S.C.R. 1010.

Terrorism

The risk of terrorism appears to be growing based on the high profile of the petroleum industry in Canada and the reliance of the U.S. 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 its Human Resources Protection Program, Crisis Management Plan and insurance programs where available.

CRITICAL ACCOUNTING ESTIMATES

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2008 of $16,389.6 million, or 66% 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, except the Corporate segment. 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. Reflecting the resource resiliency of the basins the Company serves, revised assumptions have typically resulted in extending useful lives.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services 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 generally accepted accounting principles 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, 2008, the Company's regulatory assets totaled $625.5 million (2007 – $548.4 million) and regulatory liabilities totaled $102.6 million (2007 – $173.7 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) other than pensions 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 decline in the capital markets has reduced the current market value of the plan assets; however, the discount rate has increased resulting in a lower expected benefit obligation substantially offsetting the decline in the plan assets. The Company remains able to pay the current benefit obligations using cash from operations. See Note 25 to the 2008 Annual Consolidated Financial Statements for disclosure of the difference between the actual and the expected results for the past two years. Pension expense is recorded within all of the Company's business segments with the exception of EGD which records pension expense on a cash basis in accordance with rate regulated accounting.

Assuming no discretionary funding is made into the pension plans, funding in 2009 will be approximately $48 million which is not considered significant to the Company.

(millions of Canadian dollars)	Pension Benefits		OPEB	
Impact of a 0.5% Change in Key Assumptions	Obligation	Expense	Obligation	Expense
Decrease in discount rate	74.6	9.7	12.9	1.3
Decrease in expected return on assets	n/a	6.1	n/a	0.2
Decrease in rate of salary increase	(19.2)	(4.8)	–	–

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 Enbridge Gas Distribution Inc. and Enbridge Energy Company, Inc., are disclosed in Note 29 of the 2008 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing 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 present value of expected future cash flows is determined using assumptions such as the probability of abandonment in place versus removal and the estimated costs required upon abandonment in each case, the discount rate and the estimated time to abandonment. For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing, the long-lived nature of the assets and the scope of the asset retirements. Changes in any of these assumptions could materially affect the asset and liability recognized in respect of asset retirement obligations as well as the resulting accretion of the liability and depreciation of the asset within any of the Company's business segments.

CHANGE IN ACCOUNTING POLICIES

Information about the Company's changes in accounting policies is included in Note 2 of the 2008 Annual Consolidated Financial Statements.

FUTURE ACCOUNTING POLICIES

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Canadian Accounting Standards Board confirmed in February 2008 that publicly accountable entities will be required to adopt International Financial Reporting Standards (IFRS) for interim and annual financial statements on January 1, 2011. The Company, as an SEC Registrant, has the option to use U.S. GAAP instead of IFRS. During the fourth quarter 2008, the Company chose IFRS since it

believes that IFRS will provide a more transparent and appropriate presentation of financial results, and it would avoid the cost of a second conversion when the United States converges with IFRS in or about 2014 as planned.

Enbridge has established an IFRS governance structure to monitor the progress of the transition. This group is comprised of senior management from finance, treasury, tax and the Company's business units among others. The Audit, Finance and Risk Committee of the Board of Directors receives regular reports on the advancement of the IFRS transition plan. In addition, the Company has trained internal IFRS team members and has hired a public accounting firm to assist with project management and technical accounting advice, as needed.

The Company has a multiyear transition plan which includes four phases – diagnostic, project planning, policy design and implementation. In 2008, the Company completed the diagnostic phase and has identified the relevant differences between Canadian GAAP and IFRS. The Company is in the policy design stage and is also assessing the impact of policy alternatives on its financial statements, systems, processes and controls. As the transition progresses, the Company will provide increased clarity into the anticipated consequences of accounting policy changes. The Company is in the process of developing a detailed project plan for 2009 and 2010 which will include staff communications, a training plan and an external stakeholders communication plan. Policy design will be completed in 2009 and implementation will begin during 2009 and be completed by the end of 2010.

Changes in accounting policies and processes and collection of additional information for disclosure will require modifications to the Company's information technology systems and processes as well as its system of internal controls. The identified information technology system alterations are being incorporated into the detailed project plan to allow time to modify and test the systems before implementation during 2010. The impact on internal controls over financial reporting and disclosure controls and procedures will be determined during the policy design and implementation phases.

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 U.S securities law. As of the year ended December 31, 2008, 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 Inc. 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, 2008, 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, 2008.

During the year ended December 31, 2008, 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.

QUARTERLY FINANCIAL INFORMATION [1]

2008	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**3,967.8**	**3,871.5**	**4,368.5**	**3,923.5**	**16,131.3**
Earnings applicable to common shareholders	**251.3**	**657.7**	**148.4**	**263.4**	**1,320.8**
Earnings per common share	**0.70**	**1.83**	**0.41**	**0.72**	**3.67**
Diluted earnings per common share	**0.70**	**1.81**	**0.41**	**0.71**	**3.64**
Dividends per common share	**0.33**	**0.33**	**0.33**	**0.33**	**1.32**

2007	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	3,358.2	2,728.7	2,634.0	3,198.5	11,919.4
Earnings applicable to common shareholders	227.0	146.5	78.1	248.6	700.2
Earnings per common share	0.65	0.41	0.22	0.70	1.97
Diluted earnings per common share	0.64	0.41	0.22	0.69	1.95
Dividends per common share	0.3075	0.3075	0.3075	0.3075	1.23

1 Quarterly Financial Information has been extracted from financial statements prepared in accordance with generally accepted accounting principles.

Revenue includes amounts billed to customers of EGD for natural gas, which varies with fluctuations in the commodity price. Higher natural gas commodity prices increase revenues, but would not similarly impact earnings, given the cost of natural gas flows through to customers. Fluctuations in commodity prices impact revenues and earnings from Energy Services businesses.

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

- Fourth quarter earnings in 2008 included higher contributions from Aux Sable and Energy Services, Liquids Pipelines and EGD. EGD's fixed charge per customer increased with a corresponding decrease in the per unit volumetric charge. These changes modify the quarterly earnings profile, but do not materially affect full year earnings as revenues are shifted from the colder winter quarters to the warmer summer quarters.

- Third quarter earnings in 2008 reflected increased earnings from Athabasca System, EGD, Aux Sable and Energy Services. Revenues increased due to higher average commodity prices in 2008.
- Second quarter 2008 earnings included a gain on the sale of the Company's investment in CLH as well as increased earnings from EEP, Aux Sable and Energy Services. Revenues were higher than the comparable 2007 period due to higher commodity prices impacting Energy Services.
- First quarter 2008 earnings included higher contributions from EGD as well as improved results in Aux Sable and Energy Services, partially offset by the recognition of an income tax charge related to previously owned U.S. pipeline assets. Revenues were higher than the comparable 2007 period due to higher commodity prices impacting Energy Services.
- Fourth quarter earnings in 2007 included the impact of tax changes, which increased consolidated earnings.
- Third quarter 2007 included a loss from Aux Sable.
- Second quarter 2007 included higher earnings from EGD due to colder than normal weather and a dilution gain in EEP.
- First quarter 2007 included higher earnings from EGD due to colder weather than the prior year period and the receipt of 2005 hurricane insurance proceeds.

FOURTH QUARTER 2008 HIGHLIGHTS

Earnings applicable to common shareholders were $263.4 million, or $0.72 per share, for the three months ended December 31, 2008, compared with $248.6 million, or $0.70 per share, for the three months ended December 31, 2007. Significant factors that increased earnings included unrealized fair value gains on derivative financial instruments in Aux Sable and Energy Services, AEDC in Liquids Pipelines and a higher contribution from EGD, partially offset by decreased earnings from International as the Company sold its interest in CLH in the second quarter of 2008.

SELECTED ANNUAL INFORMATION

(millions of Canadian dollars, except per share amounts)	**2008**	2007	2006
Total Revenues	**16,131.3**	11,919.4	10,644.5
Common Share Dividends	**489.3**	452.3	403.1
Total Assets	**24,701.4**	19,907.4	18,379.3
Total Long-Term Liabilities	**13,976.1**	11,117.4	10,544.8
Earnings per Common Share	**3.67**	1.97	1.81
Diluted Earnings per Common Share	**3.64**	1.95	1.79
Dividends Per Common Share	**1.32**	1.23	1.15

Total assets and long-term liabilities increased primarily because of investments in organic growth projects.

NON-GAAP RECONCILIATIONS

(millions of Canadian dollars)	**2008**	2007	2006
GAAP earnings as reported	**1,320.8**	700.2	615.4
Significant after-tax non-operating factors and variances:			
Liquids Pipelines			
Enbridge System – impact of tax changes	**–**	(1.2)	–
Feeder Pipelines and Other – asset impairment loss	**4.1**	–	–
Gas Pipelines			
Alliance Pipeline US – shipper claim settlement	**(2.8)**	–	–
Offshore – property insurance recovery from 2005 hurricanes, net of repair costs	**–**	(5.3)	–
Sponsored Investments			
EEP – dilution gain on Class A unit issuance	**(4.5)**	(11.8)	–
EEP – unrealized derivative fair value (gains)/losses	**(7.2)**	6.3	(6.5)
EEP – gain on sale of Kansas Pipeline Company	**–**	(3.0)	–
EEP – impact of 2008 hurricanes and project write-offs	**2.2**	–	–
EIF – Alliance Canada shipper claim settlement	**(1.3)**	–	–
EIF – impact of tax changes	**–**	(1.9)	(6.0)
Gas Distribution and Services			
EGD – colder/(warmer) than normal weather	**(23.1)**	(14.2)	36.9
EGD – provision for one-time charges	**2.8**	–	–
EGD/Noverco – impact of tax changes	**–**	(26.8)	(28.9)
Noverco – dilution gains	**–**	–	(4.0)
Energy Services – unrealized derivative fair value (gains)/losses	**(22.6)**	2.4	–
Energy Services – SemGroup and Lehman bankruptcies	**5.7**	–	–
Aux Sable – unrealized derivative fair value (gains)/losses	**(54.5)**	28.1	–
Other – gain on sale of investment in Inuvik Gas	**(4.6)**	–	–
International			
CLH – gain on sale of investment	**(556.1)**	–	–
CLH – gain on land sale	**–**	(5.2)	–
Corporate			
Gain on sale of corporate aircraft	**(4.9)**	–	–
U.S. pipeline tax decision	**32.2**	–	–
Unrealized derivative fair value gains	**(26.2)**	–	–
Asset impairment loss	**17.3**	–	–
Impact of tax changes	**–**	(31.1)	(14.0)
Adjusted earnings	**677.3**	636.5	592.9

OUTSTANDING SHARE DATA

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	373,032,095
Total issued and outstanding stock options (7,535,744 vested)	14,364,183

Outstanding share data information is provided as at February 4, 2009.

RELATED PARTY TRANSACTIONS

Information about the Company's related party transactions is included in Note 28 of the 2008 Annual Consolidated Financial Statements.

Additional information relating to Enbridge, including the Annual Information Form, is available on www.sedar.com.

Dated February 19, 2009