U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

o REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

OR

þ ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005 Commission file number 0-21080

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Not Applicable
(Translation of Registrant's Name into English (if applicable))

Canada	**4923**	**None**
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number (if applicable))*	*(I.R.S. Employer Identification Number (if applicable))*

3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone Number: (403) 231-3900
(Address and telephone number of Registrant's principal executive offices)

Enbridge (U.S.) Inc.
1100 Louisiana, Suite 3200
Houston, Texas 77002
Telephone Number: (713) 650-8900
(Name, address (including zip code) and telephone number *(including area code) of agent for service in the United States)*

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this Form:

þ Annual Information Form þ Audited annual financial statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

348,988,815 Common shares (as at December 31, 2005)

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

o Yes þ No

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

þ Yes o No

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the period covered by this report, an evaluation was carried out under the supervision of and with the participation of the Registrant's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of the Registrant'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 the Registrant 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.

No significant changes were made in the Registrant's internal control over financial reporting or in other factors during the period covered by this annual report on Form 40-F that have materially affected or are reasonably likely to materially affect the Registrant's internal control over financial reporting.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's Board of Directors has determined that Messrs. W.R. Fatt and D.A. Leslie, members of the Audit Committee, each qualify as an audit committee financial expert (as defined in Form 40-F under the Securities Exchange Act of 1934) and are independent as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers. The SEC has indicated that the designation of each of Messrs. Fatt and Leslie as an audit committee financial expert does not make either an "expert" for any purpose, impose any duties, obligations or liability on either of them that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted a code of ethics (the "Statement on Business Conduct") that applies to all employees and officers, including its principal executive officer, principal financial officer and principal accounting officer. The Statement on Business Conduct is available at the Registrant's Internet website, www.enbridge.com.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP (or a predecessor firm, Price Waterhouse) ("PwC") have been the auditors of the Registrant since 1992.

In response to legislative and regulatory requirements regarding auditor independence, the Registrant's Audit, Finance & Risk Committee adopted a policy that requires pre-approval by the Audit, Finance & Risk Committee of any services to be provided by the auditors, whether audit or non-audit services. During the years ended December 31, 2004 and 2005, all audit and non-audit services were pre-approved by the Audit, Finance & Risk Committee.

The following table sets forth all services rendered by the auditors by category, together with the corresponding fees billed by the auditors for each category of service for the financial years ended December 31, 2004 and 2005.

	Years ended December 31	
	2005	2004
Audit Fees(1)	$1,658,869	$1,096,423
Audit-Related Fees(2)	166,552	1,660,155
Tax Fees(3)	210,490	166,801
All Other Fees(4)	32,360	80,063
Total Fees	$2,068,271	$3,003,442

Notes:

1 Represents the aggregate fees billed by the Corporation's auditors for audit services.

2 Represents the aggregate fees billed for assurance and related services by the Corporation's auditors that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not included under "Audit Fees". This amount includes $1,280,000 for Sarbanes-Oxley Act related procedures in 2004.

3 Represents the aggregate fees billed for professional services rendered by the Corporation's auditors for tax compliance, tax advice and tax planning.

4 Represents the aggregate fees billed for products and services provided by the Corporation's auditors other than those services reported under "Audit Fees", "Audit Related Fees" and "Tax Fees".

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements as defined by Form 40-F under the Securities Act of 1934.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

Payments due for contractual obligations of the Registrant 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	6,662.5	400.0	788.4	950.0	4,524.1
Non-recourse long-term debt	1,563.0	66.7	155.7	244.5	1,096.1
Long-term contracts	822.5	190.9	217.0	196.4	218.2
Capital and operating leases	85.0	5.1	10.3	11.0	58.6

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant is required by Canadian law to have an audit committee. The Chair of the Audit, Finance & Risk Committee is R.W. Martin and the other members are E.S. Evans, W.R. Fatt, D.A. Leslie and L.D. Hyndman.

FORWARD-LOOKING STATEMENTS

A number of statements in the documents incorporated by reference in this Form 40-F constitute “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Please refer to the last paragraph on the Table of Contents in the Annual Information Form of Enbridge Inc. for the year ended December 31, 2005, dated March 3, 2006, incorporated herein and forming an integral part of this document, for a discussion of risks, uncertainties and assumptions that could cause actual results to vary from those forward-looking statements.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.

Date: March 6, 2006

By: /s/ Alison T. Love
Alison T. Love
Vice President & Corporate Secretary

EXHIBIT INDEX

99.1 Certificates of the Chief Executive Officer and Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002*.

99.2 Certificates of the Chief Executive Officer and Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002*.

99.3 Annual Information Form of the Registrant dated March 3, 2006.

99.4 Audited financial statements of the Registrant and notes thereto for the fiscal years ended December 31, 2004 and 2005 and Auditor's Report thereon.

99.5 Management's Discussion and Analysis of the Registrant for the year ended December 31, 2004 dated February 1, 2006.

99.6 Consent of PricewaterhouseCoopers LLP, independent auditors of the Registrant.

EXHIBIT 99.1

CERTIFICATIONS

Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Patrick D. Daniel, Chief Executive Officer of Enbridge Inc., certify that:

1. I have reviewed this annual report on Form 40-F of Enbridge Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (and persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 6, 2006

/s/ Patrick D. Daniel
Patrick D. Daniel
President & Chief Executive Officer

EXHIBIT 99.1

CERTIFICATIONS

Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Stephen J. Wuori, Chief Financial Officer of Enbridge Inc., certify that:

1. I have reviewed this annual report on Form 40-F of Enbridge Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (and persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 6, 2006

/s/ Stephen J. Wuori
Stephen J. Wuori
Group Vice President & Chief Financial Officer

EXHIBIT 99.2

CERTIFICATIONS

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002

Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Patrick D. Daniel, President & Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, this 6th day of March, 2006.

/s/ Patrick D. Daniel
Patrick D. Daniel
President & Chief Executive Officer

EXHIBIT 99.2

CERTIFICATIONS

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002

Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Stephen J. Wuori, Group Vice President & Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, this 6th day of March, 2006.

/s/ Stephen J. Wuori
Stephen J. Wuori
Group Vice President & Chief Financial Officer

Exhibit 99.3



ENBRIDGE INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2005

March 3, 2006

ENBRIDGE INC.
ANNUAL INFORMATION FORM
For the Year Ended December 31, 2005

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Metric Conversion: 1 barrel of liquid hydrocarbons = 0.159 cubic metre; 1 mile = 1.609 kilometres; 1 barrel mile = 0.256 cubic metre kilometre; 1 cubic foot of natural gas = 0.0283 cubic metre.

Amounts, unless otherwise stated, are in Canadian currency.

Certain information provided in this Annual Information Form constitutes forward-looking statements. The words "anticipate", "believe", "estimate", "expect", "forecast", "project" and similar expressions are intended to identify "forward-looking statements", which include statements relating to pending and proposed projects. Such statements reflect the Company's current views with respect to future events and are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, weather and economic conditions, and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers.

CORPORATE STRUCTURE

INCORPORATION

Enbridge Inc. (Enbridge or the Company) was incorporated on April 13, 1970 under the Companies Act of the Northwest Territories as Gallery Holdings Ltd. and was continued under the Canada Business Corporations Act (the CBCA) on December 15, 1987 under the name 159569 Canada Ltd. The Articles of Continuance were amended on August 2, 1989 to change the registered office to Calgary, Alberta; on April 30, 1992 to change the number of shares authorized for issuance to an unlimited number of common and preferred shares, to change the name to Interprovincial Pipe Line System Inc., and to change the registered office to Edmonton, Alberta; on July 2, 1992 to change the French version of the name to Réseau de Pipelines Interprovincial Inc.; and on August 6, 1992 to change the number of directors to a minimum of 1 and a maximum of 15, as fixed by the Board of Directors.

The Company, formerly a wholly-owned subsidiary of Interprovincial Pipe Line Inc. (Interprovincial), became the parent company of Interprovincial on December 18, 1992, pursuant to a Plan of Arrangement implementing a corporate reorganization approved by Interprovincial's shareholders at the Annual and Special Meeting of Shareholders held on May 6, 1992. As a result of the reorganization, each common share of Interprovincial was deemed to be exchanged for one common share of the Company. The shares of Interprovincial, which was incorporated in 1949 by a special act of Parliament, were listed for trading on the Toronto and Montreal stock exchanges in 1953.

The Articles of Continuance were further amended on May 5, 1994 to change the name of the Company to IPL Energy Inc. and to change the registered office to Calgary, Alberta. On October 6, 1998, the Articles of Continuance were amended to change the name of the Company to Enbridge Inc. On November 24, 1998, the Articles of Continuance were amended to increase the capital of the Company by designating a new series of preference shares as 5.5% Cumulative Redeemable Preference Shares, Series A. On April 29, 1999, the Articles of Continuance were further amended to divide each issued and outstanding common share on a two for one basis and to provide the Board of Directors with a process to add directors between meetings of the shareholders. On May 20, 2005, the Articles of Continuance were further amended to divide each issued and outstanding common share on a two for one basis.

The Company's head office is located at 3000, 425-1 st Street SW in Calgary, Alberta.

SUBSIDIARIES

Each subsidiary listed below is 100% owned by the Company unless otherwise noted. Numerous subsidiaries, many of which are inactive, are omitted from the following list. Individually the total revenue and assets for each of these excluded subsidiaries is less than 10% of the consolidated revenue and consolidated assets of the Company. In the aggregate, for excluded subsidiaries, total revenue and total assets are less than 20% of the consolidated revenue and consolidated assets of the Company.

Name	Jurisdiction of Incorporation
IPL System Inc.	Alberta
Enbridge Pipelines Inc.	Canada
Enbridge Energy Company, Inc.	Delaware
Enbridge Pipelines (NW) Inc.	Canada
Enbridge Energy Distribution Inc.	Canada
Enbridge Gas Distribution Inc.	Ontario
Enbridge (U.S.) Inc.	Delaware
Enbridge Gas Services (U.S.) Inc.	Delaware
IPL AP Holdings (U.S.A.) Inc.[1]	Delaware
Enbridge Gas Services Inc.	Canada
Enbridge Pipelines (Athabasca) Inc.	Alberta
Enbridge Capital ApS	Denmark
Enbridge Income Fund[2]	Alberta
Tidal Energy Marketing Inc.	Canada

Notes:

1 IPL AP Holdings (U.S.A.) Inc. owns the Company's 50% joint venture interest in Alliance Pipeline US.

2 The Company owns 41.9% of Enbridge Income Fund (EIF) and is the primary beneficiary of EIF through a combination of the voting interest and an investment in preferred units and as such, EIF is consolidated starting January 1, 2005 under Variable Interest Entity accounting rules.

GENERAL DEVELOPMENT OF THE BUSINESS

Enbridge's primary business activities are the transportation and distribution of crude oil and natural gas. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Sponsored Investments, Gas Distribution and Services, and International.

- Liquids Pipelines includes the operation of the Canadian common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons.
- Gas Pipelines consists of proportionately consolidated investments in pipelines that transport natural gas including the U.S. portion of the Alliance Pipeline, Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.
- Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) and Enbridge Income Fund (EIF). The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids in the U.S. EIF is a publicly traded income fund whose primary operations include a 50% interest in the Canadian portion of the Alliance Pipeline and a 100% interest in a crude oil and liquids pipeline and gathering system.
- Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, and the Company's proportionately consolidated investments in CustomerWorks, a customer care company serving natural gas distribution companies, and Aux Sable, a natural gas fractionation and extraction business. The Company's commodity marketing businesses are also included in Gas Distribution and Services.
- The Company's International business consists of two investments in liquids pipelines outside of North America.

THREE YEAR HISTORY

Significant events and transactions in the development of the Company's business over the last three years include the negotiation of a new Incentive Tolling Settlement (ITS) with the Canadian Association of Petroleum Producers (CAPP) on the Enbridge System (described under Liquids Pipelines) in 2005 and the initiation of a number of strategic organic growth projects and acquisitions. Certain organic growth projects are described in detail in the Company's 2005 Management's Discussion and Analysis, filed on SEDAR. The projects which are expected to meaningfully influence the general development of the business are described below.

Progress on Projects Under Development

The Gateway Project

Enbridge plans to build a condensate import pipeline from Canada's west coast to Edmonton, Alberta, which would provide transportation for offshore condensate supply, and a petroleum export pipeline, which would transport crude oil from Edmonton to the Canadian west coast. The condensate import line is expected to cost approximately $1.7 billion (in 2005 dollars) and the petroleum export line would cost approximately $2.5 billion (in 2005 dollars) on a stand-alone basis. If both parts of the project proceed together, total savings of approximately $550 million could be realized. Enbridge has also offered condensate line shippers the option to participate, as partners, in the ownership of that pipeline. Final commitment amounts and agreements, as well as equity participation agreements, are nearing the final stages of negotiations. The Open Season for the crude

oil export pipeline, which closed in December 2005, resulted in non-binding expressions of interest in excess of 400,000 barrels per day (bpd), supporting the continued preparations to file a full regulatory application in 2006. The decision to proceed with the regulatory filing for either pipeline is subject to commercial considerations, including satisfactory completion of shipper agreements, environmental assessment as well as public and Aboriginal consultation. If the Project proceeds, construction could begin as early as 2008 with a target in-service date early in 2010.

Waupisoo Pipeline Project

In 2005, Enbridge reached agreements with shippers on long-term transportation commitments on the proposed Waupisoo Pipeline. The 30-inch diameter, 380-kilometer long pipeline will transport crude oil from the Cheecham terminal, currently under construction on the Athabasca System (described under Liquids Pipelines), to the Edmonton, Alberta area. The initial capacity of the line will be 350,000 bpd and is expandable to a maximum of 600,000 bpd through the addition of pumping units. Enbridge has filed an application for regulatory approval with the Alberta Energy and Utilities Board (AEUB) and other provincial government departments. Pending regulatory approvals which are, expected in mid-2006, Enbridge will begin construction on the approximately $400 million (in 2005 dollars) pipeline in 2007, with an expected in-service date of mid-2008. Based on interest expressed by oil sands producers, Enbridge is including a 16-inch, 150,000 bpd diluent return line from the Edmonton area refinery hub north to the oil sands within the scope of the project for regulatory approval and public consultation. The diluent line is expected to cost approximately $200 million (in 2005 dollars). Shipping commitments on the diluent line have not been finalized.

Surmont and Long Lake Oil Sands Projects

In 2005, the Company entered into final 25 year agreements with shippers to provide transportation services commencing during the second half of 2006. Enbridge will construct, own and operate the pipelines and facilities required by the Surmont and Long Lake Projects. The total cost is estimated to be approximately $87 million.

Southern Access Mainline Expansion and Extension Program

On December 23, 2005, EEP, Enbridge's 10.9%-owned affiliate, filed a tolling application with the Federal Energy Regulatory Commission (FERC) with respect to the 400,000 bpd Southern Access expansion from the Canada/U.S. border near Gretna, Manitoba to Griffith, Indiana. On February 9, 2006, EEP announced that the diameter of the pipeline expansion will be increased from 30 inches to 36 inches. The FERC filing is endorsed by CAPP and a FERC decision is expected in the first quarter of 2006. The cost of the expansion, including the larger pipeline size, is estimated to be approximately US$1,040 million to EEP (in 2005 dollars). The program is scheduled to be brought into service in stages, with 44,000 bpd in 2007, an additional 146,000 bpd in 2008 and the final 210,000 bpd in 2009.

Enbridge has also completed negotiations in respect of the Canadian expansion agreement with CAPP for the Southern Access Expansion between Hardisty, Alberta and the Canada/U.S. border, near Gretna, Manitoba. Enbridge intends to apply to the National Energy Board (NEB) for approval of the Canadian expansion in 2006, the cost of which is estimated at US$135 million (in 2005 dollars) to Enbridge. The Canadian facilities can also be staged, and the in-service dates will be timed to coincide with the U.S. facilities.

Enbridge continues to discuss the extension of the mainline from Flanagan, IL to Patoka, IL or potentially Wood River, IL with shippers. The extension would involve the construction of a new 30-inch diameter, 300,000 bpd pipeline, at a cost of approximately US$250 million to US$320 million (in 2005 dollars) to Enbridge.

Alberta Clipper Pipeline

Enbridge anticipates that additional capacity to the U.S. Midwest, over and above Southern Access, described above, will be required. The Company has been actively developing the next tranche of mainline expansion capacity, known as the Alberta Clipper Pipeline, with selected shippers. The Alberta Clipper Pipeline project involves a new 36" line from Hardisty, Alberta to Superior, Wisconsin where it will interconnect with the existing mainline system to provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing. The line is expected to involve a total investment of approximately US$1.6 billion (in 2005 dollars) for an initial capacity

of 400,000 bpd. Shipper interest to date has been strong, and the Company will continue these discussions with shippers during the first quarter of 2006 to seek broad industry support.

EEP

EEP has actively pursued growth through a number of strategic acquisitions and organic growth projects. In January 2006, EEP announced that it has received customer commitments to support the construction of a US$530 million expansion and extension of its East Texas natural gas system (Project Clarity). The Project will handle growing natural gas production in East Texas and will consist of a 36 inch intrastate pipeline with a capacity of approximately 700 million cubic feet per day (mmcf/d), a 250 mmcf/d treating facility and a number of upstream facilities, including gathering pipelines all of which are expected to be fully operational in late 2007.

Ontario Wind Project

Enbridge will develop 200 megawatts of wind power on the eastern shore of Lake Huron in Ontario. Construction will commence in mid-2006 and total capital expenditures are expected to be approximately $400 million. Enbridge has entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all of the power produced at this facility.

2005 Transactions and Events

New ITS

The new ITS, negotiated in 2005, defines the methodology for calculating tolls on the core component of the Enbridge System in Canada. The new ITS is in effect from January 1, 2005 to December 31, 2009 and excludes minor pipelines that have their own tolling arrangements as well as expansions to the Enbridge System known as the SEP I, SEP II and Terrace expansions, which have separate tolling arrangements described under Liquids Pipelines.

Olympic Pipe Line

In December 2005, Enbridge announced that it had agreed to acquire a 65% interest in the Olympic Pipe Line Company (Olympic) from Arco MidCon LLC, a wholly owned subsidiary of BP, for US$99.8 million, subject to working capital adjustments. The transaction closed on February 1, 2006. Olympic owns 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 640 kilometres (400 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland and consists of 480 kilometres (300 miles) of 6-to-20 inch diameter pipe, a 500,000-barrel products terminal, 9 pumping stations and 21 delivery points or facilities. Olympic is the sole supplier of jet fuel to the Seattle-Tacoma International Airport and is a major supplier to the Portland International Airport. BP will continue to operate the pipeline system.

Spearhead Pipeline

Enbridge acquired 90% of the Spearhead Pipeline in 2003 and the remaining 10% in 2005. The Company has reversed the flow of the pipeline, which previously operated from Cushing to Chicago, to bring crude oil from Chicago to Cushing. The reversed pipeline went into service in March 2006.

Enbridge Offshore Pipelines

During 2005, the Company acquired further interests in Neptune Pipeline and Garden Banks Gas Pipeline, businesses included in Enbridge Offshore Pipelines. The Company also initiated a project to construct and operate both a natural gas lateral and a crude oil lateral to connect the deepwater Neptune oil and gas field to existing Enbridge Offshore Pipelines infrastructure. The project is expected to cost approximately US$125 million and is expected to be completed in 2007.

2004 Transactions and Events

EEP

At the end of 2005, the Company had an effective 10.9% ownership interest in EEP (2004 — 11.6%; 2003 — 12.2%). EEP has actively pursued growth through a number of strategic acquisitions and organic growth projects. Strategic acquisitions include the acquisition of the North Texas Natural Gas System on January 6, 2005, for approximately US$165.0 million, which consists of approximately 3,540 kilometres (2,200 miles) of gas gathering pipelines and three processing plants and the acquisition of the Mid-Continent System on March 1, 2004 for US$117 million. The Mid-Continent System consists of over 770 kilometres (480 miles) of crude oil pipelines and 9.5 million barrels of storage capacity, primarily located in Cushing, Oklahoma. In 2003, EEP acquired natural gas gathering and processing assets in north Texas for US$249.7 million.

Enbridge Offshore Pipelines

On December 31, 2004, the Company completed the purchase of ownership interests ranging from 22% to 80% in natural gas pipeline systems in the Gulf of Mexico from Shell for approximately $754 million. The assets, referred to as Enbridge Offshore Pipelines, include ownership interests in 11 transmission and gathering pipelines that transport approximately 3 billion cubic feet (bcf) per day of natural gas. The assets, which are held primarily through joint venture interests, transport approximately 50% of all deepwater production in the Gulf of Mexico.

In 2004, Enbridge sold its investment in AltaGas Income Trust resulting in an after-tax gain of $97.8 million.

2003 Transactions and Events

On October 1, 2003, the Company purchased an additional 15% interest in Vector Pipeline Partnership for approximately $97.7 million, including the assumption of $61.5 million in debt, increasing the Company's ownership interest from 45% to 60%. As a result of this additional investment, the Company established joint control effective October 1, 2003. In 2003, the Company also purchased additional interests in both Alliance Pipeline and Aux Sable for a total cost of approximately $223 million, increasing the Company's interest in both Alliance Pipeline Canada and Alliance Pipeline US from 37.1% to 50%, and increasing the Company's interest in Aux Sable from 30.9% to 42.7%. As a result, the Company established joint control of both Alliance Pipeline and Aux Sable, effective April 1, 2003. The Company's 50% interest in Alliance Pipeline Canada was sold to EIF in June 2003.

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, the Company sold its 50% interest in Alliance Pipeline Canada together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. to EIF for total proceeds of $905.0 million.

On April 1, 2003, Phase III of the Terrace Expansion Project (Terrace) was completed at a cost of approximately $120 million on the Enbridge System and approximately US$193 million on the Lakehead System. This has increased mainline system capacity by 140,000 bpd.

DESCRIPTION OF THE BUSINESS

REVENUES BY SEGMENT

(Canadian dollars in millions)	**2005**	2004	2003
Liquids Pipelines	**881.0**	872.7	821.5
Gas Pipelines	**364.3**	271.7	222.1
Sponsored Investments[1]	**249.0**	—	—
Gas Distribution and Services[2,3]	**6,947.1**	6,631.1	4,659.1
International	**11.7**	32.3	26.2
Corporate	**—**	—	0.1
Total Revenues	**8,453.1**	7,807.8	5,729.0

Notes:

1 Prior to 2005, earnings from EEP and EIF were accounted for as investment income and were therefore not included in revenues. Starting in 2005, the Company consolidates EIF under Variable Interest Entity accounting guidelines.

2 Gas Distribution and Services includes 15 months of revenues in 2004 for Enbridge Gas Distribution and other gas distribution businesses, all of which changed their year end to December 31 in 2004.

3 The Company has reclassified the revenues and cost of sales attributable to its marketing business, included in Gas Distribution and Services, to reflect the gross amounts. Previously, the Company had reported these balances on a net basis.

LIQUIDS PIPELINES

Enbridge has ownership in, and operates, the world's longest liquid petroleum pipeline system. The mainline system (the System) consists of the Enbridge System (the portion of the System located in Canada) and the Lakehead System (the portion of the System located in the United States), which is owned by EEP. The Company has an equity investment in EEP that is included in Sponsored Investments. The Athabasca System transports synthetic and heavy crude oil from the Athabasca and Cold Lake regions of Alberta to Hardisty, Alberta. The Norman Wells (NW) System transports crude oil from the Northwest Territories to Zama, Alberta. In addition, Enbridge has interests in various feeder pipeline systems (Frontier, Toledo, Mustang and Chicap), which operate in the United States, as well as the Spearhead Pipeline, which began transporting Canadian crude oil from the Lakehead System at Chicago, Illinois to Cushing, Oklahoma in March 2006.

Enbridge System

The Enbridge System extends approximately 1,930 kilometres (1,200 miles) from Edmonton to the U.S. border near Gretna, Manitoba where it connects with the Lakehead System. It continues from the US border near Sarnia, Ontario to Toronto, Ontario with lateral lines to Nanticoke, Ontario and Niagara Falls, Ontario and includes the reversed Line 9, which extends from Montreal, Quebec to Sarnia. The Enbridge System is regulated by the NEB.

Services

The Enbridge System regularly transports up to 70 different types of liquid hydrocarbons including light, medium and heavy crude oil (including bitumen), condensate, synthetic crudes, natural gas liquids (NGL) and refined products.

The Enbridge System consists of a number of separate segments:

(i) a mainline segment that consists of five pipelines, with a capacity of 1,930,000 barrels/day from Edmonton, Alberta to the U.S. border near Gretna, Manitoba.

(ii) a Sarnia, Ontario to Toronto, Ontario segment that consists of two lines with a capacity of 150,000 bpd. The Sarnia to Toronto segment includes lateral lines from Westover, Ontario, to Nanticoke, Ontario and Niagara Falls, Ontario.

(iii) a Montreal, Quebec to Sarnia, Ontario segment, Line 9, with a capacity of 240,000 bpd.

The annual capacities noted above take into account estimated crude slate and receipt and delivery patterns and ongoing pipeline maintenance and reflect achievable pipeline capacity over long periods of time.

Significant Contracts — Tolling Agreements and Tariffs

The NEB has regulatory authority in Canada over the construction and operation of pipelines for the interprovincial transportation of liquid hydrocarbons and over matters relating to the accounting and rates of such pipelines.

Enbridge System tolls have been based on an incentive approach since 1995. The main objective of this methodology is to more closely align the interests of the Company with the interests of its shippers. It provides for the sharing with customers of the results of operating efficiencies and cost savings achieved above certain thresholds on an annual basis.

In 2005, Enbridge and CAPP approved the key terms of a new negotiated ITS, effective for January 1, 2005 to December 31, 2009. In January 2006, the NEB approved the new ITS. The new ITS continues the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In conjunction with the Terrace Agreement, the new ITS continues the throughput protection provisions ensuring the Company is insulated from negative volume fluctuations beyond its control. In addition to the incentive-based provisions in prior agreements, service and reliability metrics, collectively referred to as performance metrics, have been added to the new ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets under the new service and reliability performance metric provisions. Service metrics establish financial bonuses and penalties for prescribed performance targets related to crude oil quality management and predictability of scheduled deliveries. The reliability metric provides for bonuses and penalties associated with optimization of system capacity, which are calculated relative to annual capacity targets.

Tariffs

Tolls are calculated in accordance with various agreements. Under published tariffs for the Enbridge System, the tolls for transportation, including terminaling and tankage charges where applicable, of light crude oil from Edmonton to principal delivery points, at December 31, 2005 are set forth below.

	Canadian Toll Per Barrel
Regina, Saskatchewan	$ 0.953
U.S. border near Gretna, Manitoba	$ 1.198
Sarnia, Ontario	$ 1.392

The rates for medium and heavy crude oils are higher, while those for refined products and NGL are lower than the rates set forth in the above table to compensate for differences in costs for shipping different types and grades of liquid hydrocarbons. The Canadian portion of the Terrace Agreement toll surcharge, described below, is included in the tolls listed in the table above.

SEP II Risk Sharing Agreement

Enbridge, EEP and CAPP entered into a Risk Sharing Agreement, effective for 15 years, with respect to SEP II, a 100,000 bpd expansion completed in 1998. The Risk Sharing Agreement provides that the rate of return on the SEP II investment will be based, in part, on the utilization level of the additional capacity constructed. Higher utilization is expected to result in a greater return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. During 2005, Enbridge and EEP earned the minimum rate of return on SEP II.

Terrace Agreement Toll Surcharge

As part of the Terrace Agreement, Enbridge, EEP and CAPP agreed to a fixed toll surcharge of $0.05 per barrel for the movement of light crude from Edmonton to the Chicago area. This toll surcharge commenced on April 1, 1999, when Terrace Phase I was completed. The incremental toll is allocated between Enbridge and EEP. Unused capacity under the Terrace Agreement is incorporated in tolls in the following year.

Principal Markets

The System (comprising Enbridge System and Lakehead) is the primary transporter of crude oil from Western Canada to the United States. It is the only pipeline that transports crude oil from Western Canada to eastern Canada, serving all of the major refining centres in Ontario, as well as the Midwest region of the United States. Shipments delivered to the Enbridge System originate in oilfields and oil sands in Alberta, Saskatchewan, Manitoba, British Columbia and the Northwest Territories, and reach the Enbridge System through the NW and Athabasca Systems owned by Enbridge, as well as pipelines owned and operated by others. These pipelines connect with the Enbridge System at two receiving points in Alberta, two in Saskatchewan and one in Manitoba. In addition, the Enbridge System receives offshore crude oil through connecting pipelines at Montreal, Quebec.

Outlook on Supply

Generally, development of the oil sands resource has more than offset declining conventional production. In 2005, due to events such as a significant fire at a Suncor facility, growth in oil sands production did not offset the decline in production from conventional resources. The NEB estimates that total Western Canada 2005 production will be 2.3 million bpd[1] at the end of 2005 (2004 — 2.2 million bpd). At the end of 2004, remaining established conventional oil reserves in Western Canada were estimated to be 3.8 billion barrels[2] and remaining established reserves from oil sands were estimated at 174 billion barrels[3]. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 14% of the worldwide estimated proved reserves[4].

(1) National Energy Board 2005 Estimate Production of Canadian Crude Oil and Equivalent Table 1

(2) Canadian Association of Petroleum Producers Statistical Handbook 2005

(3) Alberta Energy and Utilities Board Alberta's Reserves 2004 and Supply/Demand Outlook

(4) Oil and Gas Journal's Worldwide Look at Reserves and Production, December 19, 2005

Deliveries and Demand for Western Canadian Sedimentary Basin Crude

The Company's liquids pipelines are dependent upon the demand for crude oil and other liquid hydrocarbons produced from Western Canada. Historically, the pipeline system has delivered crude oil to three main markets: Ontario/Quebec, and the Midwest portion of the United States with some additional volume delivered to Western Canada. Deliveries from the System are made in the prairie provinces, the Province of Ontario and in the Great Lakes and Midwest regions of the United States, principally to refineries, either directly or through the connecting pipelines of other companies. Within these regions are located major refining centres near Sarnia, Nanticoke, and Toronto, Ontario; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; Chicago, Illinois; the Patoka/Wood River, Illinois area; Detroit, Michigan; and Toledo, Ohio. Through Company initiatives, crude oil will begin to penetrate southern markets in PADD II (the U.S. Midwest) with the Spearhead Pipeline as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.

Historically, Canada has been the third largest supplier of crude to the U.S. However, for the past two years, Canada has surpassed both Mexico and Saudi Arabia to become the largest exporter of crude oil to the U.S. Western Canada demand is served by local supply and has increased by 25,800 bpd over the last two years. During 2005, an equal mix of Western Canadian and Atlantic Basin crude oil satisfied Ontario's crude oil requirements. Deliveries to Ontario from Western Canada and from Montréal, Quebec declined in 2005 with

the closure of Petro-Canada's Oakville refinery. Deliveries of WCSB crude into PADD II (the U.S. Midwest) remained relatively flat over the last two years with reduced WCSB crude oil supply in 2005. Deliveries of Canadian crude oil to the U.S. demonstrated a growth of 116,400 bpd by December compared to the third quarter of 2005, as Suncor's recovered production entered the market. Over the same two-year period, deliveries into PADD IV (the U.S. Rocky Mountains) have increased by 30,800 bpd and PADD V (the Western U.S.) deliveries have increased by 25,000 bpd.

The following table sets forth the information related to deliveries and other distance-related operating data of the Enbridge System for each of the years in the three-year period ended December 31, 2005.

	Deliveries		
(thousands of barrels per day)	**2005**	2004	2003
Prairie Provinces			
Light crude oil	182	194	176
Medium and heavy crude oil	132	126	91
Refined products	79	83	83
	393	403	350
United States			
Light crude oil	198	261	252
Medium and heavy crude oil	783	748	690
Natural gas liquids	4	4	4
	985	1,013	946
Ontario			
Light crude oil	338	403	391
Medium and heavy crude oil	58	79	68
Natural gas liquids	98	103	109
	494	585	568
	1,872	2,001	1,864
Barrel Miles (billions)	350	383	361
Average Haul (miles)	513	523	530

Enbridge System average deliveries include Line 9 volumes of 190,000 bpd (2004 — 227,000; 2003 — 216,000).

Competitive Conditions

Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, batch shipping integrity, interconnectivity with storage and proximity to markets. Kinder Morgan Canada's Trans Mountain and Express Pipeline systems, as well as other common carriers, can be used by producers to ship Western Canadian crude oil to refineries in either Western Canada or the United States. Although the Company does not compete directly in the regions served by these other pipelines, producers can elect to have their crude oil refined elsewhere than delivery points on the Enbridge System. Competition may also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. One such proposal is the Keystone Project put forward by TransCanada Corporation to ship Western Canadian crude oil into PADD II starting in 2009 or 2010. The Company believes that currently its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls and flexibility.

Other Liquids Pipelines

Athabasca System

The Athabasca System, which is owned and operated by Enbridge, has a design capacity of 570,000 bpd and extends approximately 550 kilometres (340 miles) from north of Fort McMurray in northern Alberta, south to the pipeline hub at Hardisty, Alberta. At Hardisty, it accesses the Enbridge System and other carriers for transportation to Canadian and U.S. refineries. The Athabasca System also includes the Athabasca Terminal with 1.6 million barrels of receipt tankage, as well as the MacKay River and Christina Lake lateral

feeder lines and tankage facilities. Enbridge has a 30-year take-or-pay transportation arrangement with Suncor Energy Inc., the initial shipper on the Athabasca System. The agreement also provides the shipper with options to increase and extend the life of the agreement beyond the initial 30-year term. Enbridge has also contracted to provide transportation services for EnCana Corporation and Petro-Canada Oil and Gas and, starting in 2006, for ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. (the Surmont Shippers) and Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) on pipelines and facilities currently under construction. The Athabasca System is regulated by the AEUB.

NW System

The NW System extends approximately 870 kilometres (540 miles) between Norman Wells, Northwest Territories and Zama, Alberta. The NW System is regulated by the NEB and is subject to a negotiated settlement and throughput agreement with its main shipper.

Spearhead Pipeline

The Spearhead Pipeline, which was put in service in March 2006, has a capacity of 125,000 bpd and 4.3 million barrels of tankage, and extends approximately 1,045 kilometres (650 miles) from Chicago, Illinois to Cushing, Oklahoma. The Company has 10-year shipper commitments for 60,000 bpd increasing to 70,000 bpd in 2009. Spearhead Pipeline is regulated by the FERC.

Other U.S. Liquids Pipelines

Other U.S. Liquids Pipelines are regulated by the FERC and include a 77.8% interest in the Frontier System, a 30% joint venture interest in the Mustang System, a 22.8% interest in the Chicap System, the wholly-owned Toledo System and the Patoka West Tank Farm Facility.

Safety and Environmental Protection

Enbridge has appropriate mechanisms in place to monitor and address the safety and environmental aspects of its operations. Enbridge has health, safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations.

Spills of crude oil and petroleum products are not unusual within the liquids pipeline industry and the Company has experienced such spills in the past. A comprehensive methodology for managing environmental aspects of hydrocarbon spills is in place. Historic spills along the pipeline system may have resulted in soil or groundwater contamination where further remediation may be required. Enbridge continues to voluntarily investigate past leak sites to assess whether any remediation of contaminated lands is required in light of current legislation, in consultation with regulatory agencies and landowners. To date, no material environmental risks have been identified.

The environmental protection requirements applicable to the Company's pipeline operations do not adversely affect the pipeline operations' competitive position, capital expenditures program or level of earnings. However, the risk of substantial liabilities is inherent in pipeline operations and there can be no assurance that such liabilities will not be incurred. Regular internal reviews and audits are conducted to assess compliance with legislation and company policy. To the best of the Company's knowledge, its pipeline operations are in compliance with all applicable safety and environmental regulations governing their operations.

Pipeline Integrity

The focus of Enbridge's integrity management program is to continuously monitor the condition of the pipeline system and apply preventative maintenance programs. In 2005, in-line inspections for corrosion, cracks and pipe deformities such as dents were conducted in various lines throughout the pipeline system. Investigative excavations were conducted to evaluate anomalies detected by the inspections and repairs were conducted as needed. All work plans and implementation procedures meet or exceed regulatory requirements and are regularly reviewed and continuously improved to ensure best technologies are utilized and integrity management processes are optimised.

Employees

Approximately 896 individuals are employed in the Liquids Pipelines segment within Enbridge.

GAS PIPELINES

Gas Pipelines consists 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 the US portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising the Enbridge Offshore Pipelines.

Alliance Pipeline

The Alliance Pipeline is a natural gas pipeline extending 3,000 kilometers (1,875 miles) from supply areas in northwestern Alberta and northeastern British Columbia to Chicago, Illinois. The Canadian portion of the Alliance Pipeline is 50% owned by Enbridge Income Fund, a consolidated sponsored investment.

The Alliance Pipeline has a firm delivery capacity of approximately 1.3 billion cubic feet (bcf) of natural gas per day, all of which is committed through take-or-pay transportation agreements ending in 2015, and additional transportation capacity of approximately 0.3 bcf per day which is available to shippers at no additional cost other than the cost of the associated fuel requirements. The contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, cost of financing, an allowance for income tax, an annual allowance for depreciation, and an allowed return on equity. Each contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. The rates and tariff for Alliance Pipeline US are regulated by the FERC.

The Alliance Pipeline connects in the Chicago area with two local natural gas distribution systems and five interstate natural gas pipelines, which provide shippers access to natural gas markets in the Midwestern and northeastern United States and eastern Canada. It also interconnects with a pipeline in North Dakota. The Alliance Pipeline connects with a NGL extraction facility (Aux Sable) in Channahon, Illinois near the terminus of the Alliance Pipeline.

Vector Pipeline

Enbridge provides operating services to the 348-mile Vector Pipeline, which transports natural gas from Chicago, Illinois to Dawn, a storage location near Dresden, Ontario. The primary source of natural gas for Vector Pipeline is through interconnection facilities established with Alliance Pipeline and Northern Border Pipeline. Vector Pipeline has a nominal delivery capacity of 1.0 bcf of natural gas per day and is expandable to 1.5 bcf per day with additional compression stations. Approximately 70% of the long haul capacity of Vector is committed to firm transportation contracts that expire in 2015 at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and various term lengths under firm and interruptible transportation service agreements. Vector Pipeline is currently operating at or near capacity. In 2005, Vector Pipeline announced plans to construct two additional compressor stations, which would expand Vector Pipeline's nominal capacity to 1.2 bcf per day, that it had obtained 10 year, binding agreements from shippers and that it had initiated the filing process with the FERC.

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines (EOP) is comprised of ownership interests in 11 natural gas gathering and transmission pipelines in five major corridors in the Gulf of Mexico and include a total of 2,380 kilometers (1,480 miles) of pipeline. The assets are held primarily through joint ventures with ownership interests ranging from 22% to 100%. EOP transports approximately 3 bcf of natural gas per day, which is approximately half of all deepwater production in the Gulf of Mexico. The rates and tariffs for EOP are regulated by the FERC, for pipelines conducting interstate business, and the Outer Continental Shelf Lands Act, for gathering laterals and are based on a mix of tariff-based and market-based rates.

All natural gas pipelines are subject to federal, state or local laws and regulations related to environmental protection and operational safety. To the best of the Company's knowledge, the operations of all affiliated systems are in substantial compliance with applicable environmental and safety regulations.

Employees

Approximately 100 individuals are directly employed by Enbridge to provide operating services to EOP. The Alliance Pipeline is operated and administered entirely by employees of Alliance Pipeline. The Vector Pipeline is operated and administered in part by employees of Vector Pipelines, and in part through operating and administrative services provided by Enbridge.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 10.9% ownership interest in EEP and a 41.9% equity 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.

Enbridge Energy Partners

Enbridge's 10.9% ownership interest in EEP is comprised of the Company's direct investment in EEP of 7.9% and an indirect investment of 3.0% through the Company's 17.2% ownership interest in EEM. EEM's business activities are limited to managing the business and affairs of EEP and holding an approximate 17.5% interest in EEP.

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 US, natural gas gathering and processing assets in east Texas (East Texas System), the mid-continent crude oil system (Mid-Continent System), which was acquired in 2004, a natural gas system in north Texas (North Texas System), which was also acquired in 2003, and a feeder pipeline in North Dakota.

Enbridge, as the general partner of EEP, receives incentive income based on the level of quarterly cash distributions. EEP makes quarterly cash distributions of all of its available cash to the holders of its common units, including Enbridge. Under the Partnership Agreement, Enbridge 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.

Enbridge Income Fund

Enbridge created EIF in June 2003. On formation, EIF acquired the Company's 50% interest in the Canadian segment of the Alliance Pipeline, as well as its 100% interest in the Enbridge Saskatchewan System. A subsidiary of Enbridge acts as EIF's manager. Enbridge holds a 41.9% interest in EIF in the form of subordinated units of EIF and 100% of the non-voting, preferred units of Enbridge Commercial Trust, a direct subsidiary of EIF.

The Canadian segment of the Alliance Pipeline consists of an approximately 1,560 km high-pressure, natural gas transmission system and an approximately 700 km lateral pipeline system. The Saskatchewan System's primary business activity is the transportation of crude oil and other liquid hydrocarbons by pipeline through the ownership and operation of the Saskatchewan, Westspur and Weyburn pipeline systems located primarily in Saskatchewan and the Virden pipeline system located in Manitoba.

Employees

Enbridge employs approximately 1,354 individuals who provide services to Sponsored Investments.

Each of EEP and EEM has filed an Annual Report on Form 10-K for the year ended December 31, 2005 with the Securities and Exchange Commission in the United States. These documents contain detailed disclosure with respect to each entity and are publicly available from the Securities and Exchange Commission and

through www.edgar.com. No part of the Form 10-K filed by EEP or by EEM is intended to be incorporated by reference in this Renewal Annual Information Form of Enbridge Inc.

EIF has filed an Annual Report and a renewal Annual Information Form (AIF) for the year ended December 31, 2005 with Canadian Securities Administrators in Canada. The AIF and the Annual Report, which includes consolidated financial statements and Management's Discussion and Analysis, contain detailed disclosure with respect to the Enbridge Income Fund and are publicly available through www.sedar.com. No part of EIF's Annual Report, consolidated financial statements, Management's Discussion and Analysis or Renewal AIF is intended to be incorporated by reference in this AIF of Enbridge Inc.

GAS DISTRIBUTION AND SERVICES

The primary component of Gas Distribution and Services is the gas distribution operations of Enbridge Gas Distribution (EGD). This segment also includes Noverco, CustomerWorks, the gas services business, which manages the Company's merchant capacity commitments on Alliance and Vector, and the Company's investment in Aux Sable.

Enbridge Gas Distribution

Principal Markets

Enbridge's gas distribution business is conducted primarily through EGD, a wholly-owned subsidiary. EGD is Canada's largest natural gas distribution utility, serving over 1.75 million residential, commercial, industrial and transportation service customers in central and eastern Ontario, including the City of Toronto and the surrounding areas of Peel, York and Durham, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. The gas distribution utility business of EGD is regulated by the Ontario Energy Board (the OEB), its principal regulator, which regulates various aspects of EGD's utility operations in Ontario.

Distribution Methods

EGD's principal source of revenue is from distribution services provided to its customers. The services provided to residential and small commercial and industrial heating customers are primarily on a general service (non-contract) basis. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm service contract, EGD is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible service contract is similar to that of a firm contract, except that it allows for service interruption at the option of EGD to meet seasonal or peak demands. The OEB approves rates for both contract and general services.

Customers have several choices in respect of gas supply. One option is the sales service option whereby the customer purchases gas from EGD's supply portfolio (system supply). EGD does not earn a profit on the gas commodity it provides to customers. Alternatively, a customer may select a direct purchase option, which is either a transportation service arrangement or a buy/sell arrangement. Under the transportation service arrangement, a customer supplies natural gas at a TransCanada PipeLines Limited (TransCanada) receipt point in Western Canada or at a TransCanada delivery point in Ontario, and EGD redelivers an equivalent amount of gas to the customer's end-use location. Under the buy/sell arrangement, a customer purchases gas directly from a Western Canadian producer or a marketer and sells it to EGD at a TransCanada receipt point in Western Canada. EGD, in turn, resells the gas, now integrated into its general supply portfolio, back to the customer at its end-use location. The buy/sell arrangements are being phased out as they expire, and are being replaced with transportation service arrangements. Both types of arrangements are billed under the OEB-approved rate schedules.

Pricing and Availability of Natural Gas

Gas Supply

To acquire the necessary volume of gas to service its customers, EGD maintains a diversified gas supply portfolio. During the year ended December 31, 2005, EGD acquired approximately 176.6 bcf of natural gas,

of which 29.4% was acquired from Western Canadian producers; 44.1% from suppliers in Chicago and 26.5% was acquired on a delivered basis in Ontario. EGD also transported 264.9 bcf of natural gas on behalf of direct purchase customers operating under a transportation service arrangement.

EGD's system supply gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts are indexed to either Alberta, Chicago or New York based prices. EGD uses natural gas financial derivatives such as price swaps, calls and collars to manage customers' exposure to natural gas price risk.

Transportation

EGD relies primarily upon TransCanada for transportation service to bring its diversified gas supply from Western Canada to its franchise area. EGD has long-term firm transportation service contracts with TransCanada, over varying time periods, for annual deliveries of approximately 300 bcf of natural gas. This includes deliveries by direct purchase customers via TransCanada capacity that has been assigned by EGD to the direct purchase customer or capacity that has been contracted directly with TransCanada by the direct purchase customer.

The transportation service contracts are not directly linked with any particular source of gas supply. Separating transportation contracts from gas supply allows EGD flexibility in obtaining its own gas supply and accommodating the transportation of natural gas purchased directly by end-use customers. EGD continues to forecast the gas supply needs of all its customers, including the associated transportation and storage requirements.

TransCanada's transportation tolls, which are approved by the NEB, consist of a fixed cost (demand component) and a variable cost (commodity component) for Firm Transportation (FT) service. An FT shipper, such as EGD, must pay the demand component regardless of the volume of gas that TransCanada actually transports for the FT shipper. Consequently, if an FT shipper does not utilize all of its FT capacity rights, the FT shipper would incur unabsorbed demand charges in respect of the unutilized portion.

EGD also has contracts for firm transportation service on the Alliance and Vector pipelines. EGD relies on its long-term contracts with Union Gas Limited (Union) for transportation from Dawn, a storage location near Dresden, Ontario, to the Company's major market in the greater Toronto area. The contracts effectively provide the Company with access to U.S.-sourced gas delivered at St. Clair, Michigan by Michigan Consolidated Gas Company (MichCon), including gas delivered to MichCon by upstream pipelines in the United States and at Dawn by the Vector Pipeline. The contracts also provide transportation for gas stored at the Company's and Union's storage pools in the Sarnia area to the market area.

EGD is also a participant in the Link Project, which involved the construction of connecting pipelines in southwestern Ontario by Niagara Gas Transmission Limited (Niagara Gas), a wholly-owned subsidiary of Enbridge, and in southwestern Michigan by ANR Pipeline Company (ANR). These pipelines effectively link ANR's southeast and southwest mainlines, which access major U.S. supply basins, and MichCon's transportation system, which accesses Michigan supplies, directly to EGD's principal storage facilities near Dawn (see "Gas Storage" below) and indirectly to Union Gas Limited's transmission system at Dawn. EGD has entered into long-term contracts for transportation service with ANR, MichCon and Niagara Gas.

Gas Storage

The business of EGD is highly seasonal as daily market demand for gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits EGD to take delivery of gas on favourable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits EGD to minimize the annual cost of transportation of gas from Western Canada, assists in reducing its overall cost of gas supply and adds a measure of security in the event of short-term interruption of transportation of gas from Western Canada to EGD's franchise area.

EGD's principal storage facilities are located in southwestern Ontario near Dawn and have a total capacity of approximately 98.9 bcf. Approximately 91.8 bcf of the total capacity is available to EGD. EGD also has a storage contract with Union Gas Limited for 20.0 bcf of storage capacity.

The EGD-operated storage facilities are connected to the Dawn storage and transmission hub by two 30-inch pipelines owned by EGD. In the summer, gas is delivered to Dawn for injection into storage through the transmission facilities of TransCanada and Vector pipelines. In the winter, gas is withdrawn from storage and delivered to Dawn and transported to EGD's major market area of Toronto through the transmission facilities of Union. EGD has transportation contracts with TransCanada, Vector and Union for the delivery of gas to and from storage.

Pursuant to a Notice of Proceeding issued by the OEB on December 29, 2005, the OEB indicated its intention to examine two issues involving gas storage. The first issue relates to rates for gas-fired generators (and other qualified customers). The second issue involves storage regulation in Ontario and, more specifically, whether the OEB should refrain, in whole or in part, from exercising its power to regulate the rates charged for the storage of gas in Ontario. Both of these issues were identified in an earlier (2005) report of the OEB entitled Natural Gas Regulation in Ontario: A Renewed Policy Framework. The Company is currently examining these issues and plans to file evidence with the OEB in the spring of 2006. A hearing is then contemplated by the OEB, to be held later in the spring or summer of 2006.

Historical Operating Statistics for EGD

	Year Ended December 31, 2005	15 Months Ended December 31, 2004	Year Ended September 30, 2003
Gas supply and sendout (mmcf) [1]			
Natural gas purchased	183,333	214,853	181,671
Gas into storage	(105,097)	(104,435)	(117,831)
Gas out of storage	96,381	126,699	101,615
Total gas sendout	174,617	237,117	165,455
Transportation of gas	264,034	337,775	295,775
Total gas and transportation gas sendout	438,651	574,892	461,230
Gas sales to customers	174,515	223,343	162,468
Transportation of gas	264,182	352,047	295,775
Total sales	438,697	575,390	458,243
Used by EGD (mmcf) [1]	170	265	219
Other volumetric variances (mmcf) [1]	(215)	(763)	2,768
	438,652	574,892	461,230
Average daily send-out (mmcf) [1]	1,194	1,264	1,261
Average use per residential customer (mcf) [1]	104	126	109
Degree day deficiency [2]			
Actual	3,750	5,052	4,029
Forecast based on normal weather	3,747	4,849	3,565
Number of active customers — year end [3]	1,774,067	1,726,857	1,652,373
Number of employees — period end	1,765	1,633	1,600

Notes:

1. mcf = thousand cubic feet mmcf = million cubic feet
2. Degree day deficiency is a measure of coldness, which is indicative of volumetric requirements of natural gas utilized for heating purposes in all markets. It is calculated by accumulating from the start of the fiscal period the total number of degrees each day by which the daily mean temperature falls below 18 degrees celsius (the figures given are those accumulated in the Toronto area).
3. Number of active customers includes gas sales and transportation service customers. As the commodity cost of gas is flowed through to gas sales customers with no mark up, the composition of customers between gas sales and transportation service has no impact on EGD's earnings.

	Year Ended December 31, 2005	15 Months Ended December 31, 2004	Year Ended September 30, 2003
Number of active customers — period end			
Residential	1,047,350	976,384	925,674
Commercial	93,686	85,338	81,289
Industrial	3,763	3,441	3,413
Wholesale	1	1	1
Transportation	629,267	661,693	641,996
Total active customers	1,774,067	1,726,857	1,652,373

Regulation

While EGD will again be under a cost of service rate setting mechanism in 2005, EGD continues to explore alternate rate-making models with the regulator.

On March 30, 2005, the OEB released its policy framework with respect to natural gas regulation in Ontario. With respect to rate regulation, the OEB expressed its belief that a multi-year incentive regulation (IR) plan with the following key parameters will meet its objectives:

- Inclusion of an appropriate annual adjustment mechanism to give effect to the combined assessment of cost changes and productivity improvements, to ensure that benefits of efficiencies are shared with customers during the term of the plan;
- Mandatory cost of service rebasing at the end of each IR plan term and before a new plan is put in place to ensure that efficiency improvements will be revealed and that the benefits are passed onto customers through base rates for the following IR plan period;
- Earnings sharing mechanisms will not form part of IR plans, in order to provide a strong incentive to achieve sustainable efficiencies that can be shared with customers through the annual adjustment mechanism and rebasing; and
- IR term plans are expected to run between three and five years.

The Company expects the IR regime to be implemented sometime in 2008.

Fiscal 2006 Rates

The Company's 2006 rate application was a traditional cost of service application. Key elements of the Company's requested / approved rates are summarized below:

Regulatory year ending	Requested for December 31, 2006	Approved September 30, 2005	Approved September 30, 2003
Rate base (millions)	$ 3,596.2	$ 3,422.1	$ 3,155.8
Deemed common equity for regulatory purposes	35.00%	35.00%	35.00%
Rate of return on common equity	8.74%	9.57%	9.69%

The rate of return on common equity is calculated with reference to a formula approved by the OEB that incorporates the long bond yield forecast. The 2006 rate application requested a rate of return of 10.11%,

which was a preliminary calculation based on the forecast yield for long bonds used in the formula at the time the 2006 rate application was made. Subsequent movements in the forecast yield for long bonds have resulted in a final rate of return on common equity of 8.74% becoming applicable for 2006.

On February 9, 2006, the OEB released its decision relating to the Company's 2006 rate application. Key elements of the decision include limiting proposed capital expenditures to $300 million, as compared to the Company's request for capital expenditures of approximately $460 million. Average annual capital expenditures incurred over the past five years have been approximately $250 million. The OEB's decision is expected to result in an overall increase in rates of less than 3% for the average residential customer. Updated information relating to the Company's rate base and rate of return on rate base, as affected by this decision, has not been finalized as of the date hereof. A copy of the OEB's decision is available at www.oeb.gov.on.ca.

2005 Rates

The Company's rates for 2005 were approved by the OEB in November 2004. A rate of return on common equity of 9.57% was applicable in 2005.

2004 Rates

The Company's fiscal 2004 rate application was not a traditional cost of service application, since it requested an increase in 2003 rates by 90 percent of the forecast Ontario consumer price index. Accordingly, no rate base information has been provided in the table above. A rate of return on common equity of 9.69% was applicable in 2004.

The Company also applied to the OEB for approval to change the regulatory rate-setting cycle to run on a calendar year basis, starting in 2006, instead of the existing October to September cycle. The change was approved by the OEB in November 2004, as part of its final decision on the 2005 rate application.

Competitive Conditions

Natural gas is the predominant fuel of choice in the residential heating market throughout EGD's franchise area. The primary competition to natural gas in the residential heating market has historically been from domestic fuel oil and electricity. In 2005, natural gas in the residential heating market experienced, on average, a price advantage on an equivalent annual volume basis of 40% (2004 — 38%) against electricity and 32% (2004 — 23%) against domestic fuel oil.

Although natural gas commodity prices remained historically high over the year, the concurrent run-up in oil prices and electricity prices have kept natural gas prices competitive with alternative energy sources. Natural gas prices have risen mainly due to steady increases in demand and tight short-term supply. Over the longer term, supply is expected to expand with a greater North American Liquefied Natural Gas infrastructure and Arctic gas contributions.

Environment and Safety

The impact of energy usage on the environment is a significant concern with attention being focused not only on the environmental impacts associated with the production, transmission and delivery of energy, but also with respect to emissions resulting from energy use. The use of fossil fuels results in air emissions. These emissions include primarily carbon dioxide, sulphur dioxide, nitrogen oxides, total suspended particulates, and to a lesser extent, carbon monoxide and methane. However, the levels of these emissions are not the same for all fossil fuel types. Natural gas has the lowest emissions profile of any of the fossil fuels, emitting 45% less carbon dioxide (CO_2) than conventional coal-fired generation and no sulfur dioxides (SO_2). In addition, though every combustion process produces nitrogen oxides (NO_x), natural gas applications have evolved to the point where NO_x production at combustion is minimal, particularly in comparison with other fossil fuels[1].

1 Canadian Gas Association, 2005. A Sustainable Energy Future. The Role of Natural Gas.

Methane, the principal component of natural gas, is a “greenhouse gas”. Scientists are concerned that increases in greenhouse gas concentrations in the atmosphere could lead to global climate change. Although small atmospheric release of methane during the production, processing, transmission and distribution of natural gas is inevitable, studies have shown that methane emissions from the natural gas industry in Canada, relative to natural sources such as wetlands, are low. Measurements of atmospheric methane show that 70% - 80% is of biogenic origin (naturally occurring) and landfills produce the most methane from any “natural” environment[2].

Leak detection studies are on-going to identify potential sources of methane emissions in the distribution of natural gas and specific measures which can be taken to reduce these emissions. In addition, EGD is participating in a Canada-wide study to identify where the largest emission sources occur in the system through participation in a Canadian Energy Partnership for Environmental Innovation study. As well, the company is committed to its on-going participation in Canada’s GHG Challenge Registry (the old Climate Change Voluntary Challenge and Registry — VCR — Program). EGD has been recognized by that organization for its leadership and reporting qualities.

EGD has implemented measures to reduce methane emissions from its distribution system, lower the energy used in its daily business activities, encourage customer participation in the Company’s energy efficiency and demand-side management (DSM) programs, and to promote fuel-switching to natural gas from more polluting fuels. Between 1995 and the end of 2005, the Company was successful in helping its customers reduce their natural gas consumption by 2.3 billion cubic metres through participation in DSM programs. This translates into the avoidance of 4.3 million tonnes of GHG emissions being released into the atmosphere. Each of these measures moves EGD closer to the realization of its emission reduction targets, despite the pressures of significant growth in the Company’s customer base. The Company’s emission reductions are documented in the GHG Challenge Registry reports.

Programs have been implemented to ensure adherence to Enbridge’s Environment, Health and Safety policy. These include environmental training for specific employee groups, implementation of environmentally sound construction practices, production of environmental communication materials to increase awareness of key issues, environmental auditing, adoption of an environmental management system and a continuing focus on corporate due diligence. None of the environmental protection requirements applicable to EGD are expected to adversely affect its competitive position, capital expenditure program or level of earnings.

Employees

On December 31, 2005, EGD had 1,765 employees, 38% of whom were unionized and the majority of which are represented by the Communications, Energy and Paperworkers Union, Local 975. The current negotiated collective agreement expires in December 2006.

EGD has filed an AIF, financial statements and Management’s Discussion and Analysis with Canadian Securities Regulatory Authorities. These documents contain detailed disclosure about EGD and are publicly available through www.sedar.com. No part of EGD’s AIF, financial statements or Management’s Discussion and Analysis is intended to be incorporated by reference in this AIF of Enbridge Inc.

Other Gas Distribution and Services Businesses

Other businesses in the Gas Distribution and Services segment include Enbridge Gas Services, St. Lawrence Gas Company Inc., Gazifère Inc., Niagara Gas Transmission Ltd. (Niagara Gas), Tidal Energy Marketing, CustomerWorks LP (CustomerWorks), and ownership interests in Noverco, Enbridge Gas New Brunswick (EGNB), Aux Sable, Sunbridge, and Inuvik Gas.

Gazifère is a gas distribution utility located in southwestern Quebec. Niagara Gas provides transmission services to EGD, Gazifère, St. Lawrence and MichCon (an unrelated company). Enbridge Gas Services manages the Company’s merchant capacity commitments on the Alliance and Vector pipelines.

2 Soil Use and Management. Vol 13, Number 4, December 1997 Supplement.

Enbridge has a 70% joint venture interest in CustomerWorks, which provides service covering the entire meter-to-cash process, including information technology, fleet services, call management centre, customer care and billing. CustomerWorks provides services to more than 2.4 million customers including customers of Terasen and EGD. In August 2002, CustomerWorks outsourced the provision of its customer care services to a new entity owned and operated by Accenture Inc.

Enbridge owns an equity interest in Noverco through ownership of common shares and a cost investment through ownership of preferred shares. Noverco is a holding company that owns a 75% interest in Gaz Metro L.P., a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro L.P. has a 50% interest in TQM Pipeline, which transports natural gas in Quebec.

The Company owns 64% of and operates EGNB, the natural gas distribution franchise in the province of New Brunswick. EGNB constructed a new distribution system and has approximately 4,858 customers. Approximately 470 kilometres (290 miles) of distribution main has been installed with the capability of attaching 20,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Enbridge also holds a 42.7% interest in the Aux Sable natural gas liquids extraction and fractionation facility. This facility processes up to 1.6 bcf of natural gas per day delivered through the Alliance Pipeline and recovers ethane, propane, butane and pentane. In 2006, Aux Sable entered into a memorandum of agreement with BP Products North America Inc. to sell all of its NGL production to BP at its facilities near Chicago. BP will pay Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified thresholds. In addition, BP will compensate Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP will supply, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and will assume responsibility for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement will be for an initial term of 20 years, commencing December 31, 2005 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, however Aux Sable has the right to reduce such losses to avoid termination.

Enbridge conducts liquids marketing activities through its ownership of Tidal Energy Marketing Inc. (Tidal). Tidal provides crude oil marketing services for the Company and its customers in a full range of crude oil types including light sweet, light and medium sours and several heavy grades and natural gas liquids. Tidal 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's business involves buying, selling and storing large quantities of crude oil at low margins. Tidal does not trade on a speculative basis and its business is tightly monitored by, and must comply with, the Company's formal risk management policies.

Employees

Enbridge employs approximately 422 individuals in its Other Gas Distribution and Services businesses.

INTERNATIONAL

The Company's International business invests in energy transportation and related energy projects outside of Canada and the United States. This business also provides consulting and training services related to proprietary pipeline operating technologies and natural gas distribution. The Company has a 25% interest in a Spanish pipeline company, Compañia Logistica de Hidrocarburos (CLH), a 24.7% investment in the Colombian crude oil pipeline, Oleoducto Central S.A. (OCENSA), and a 100% interest in CIT Colombiana S.A. (CITCol), which is responsible for operating the OCENSA pipeline.

CLH

The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network located throughout Spain. Earnings are based on a fee for service tariff, adjusted annually for inflation, and are dependent on throughput volumes and storage levels.

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access non-discriminatory basis. The system consists of over 3,400 kilometers of pipelines and 39 storage facilities located throughout the country. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where crude oil and refined products are imported. CLH receives refined products from customers at the refineries or ports and transports them, mainly by pipeline, to its storage facilities located throughout the Spanish mainland and the Balearic Islands. The network of pipelines and storage facilities are the primary means by which the Spanish refiners and other market players supply their commercial and retail customers. CLH customers' product destinations are located, on average, less than 60 kilometers via highway from a CLH terminal. CLH provides product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships.

Based on the extensive network of pipelines and storage facilities, and its tariff structure, CLH has a dominant market position in Spain, with a total market share in 2005 of 83% for gasoline and diesel and transports 100% of aviation fuel. Most of the competition comes from storage services provided by other companies. CLH has approximately 70% of the total refined products storage capacity in Spain (excluding refineries). CLH also offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition, allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, the aviation fuel business will continue.

Earnings from CLH are directly impacted by the demand for refined products. Economic growth in Spain over the last decade has been one of the highest in the European Union, which has led to increasing demand for energy, including refined products. CLH has seen an average growth (CAGR) in its activity of 4.4% in the past five years. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH plans to expand its system over the next several years in order to meet the continued growth expected in this region. This expansion, which includes an increase in storage capacity and looping of both the northern and southern main lines, will be constructed in stages to match the expected growth in volumes.

OCENSA

The OCENSA pipeline consists of 829 kilometers (515 miles) of 30-inch and 36-inch pipeline, pumping units, tankage and marine loading facilities, with a capacity to transport 550,000 bpd of crude oil. The pipeline links the Cuisiana and Cupiagua oilfields in the central interior of Colombia to the Port of Coveñas on the Caribbean coast. The Company earns a fixed rate of return on the OCENSA pipeline investment, as well as operating fees, through its 100% interest in the operating entity, CITCol.

Environmental Protection

The international operations of Enbridge are subject to federal, state or local laws and regulations relating to environmental protection and operational safety. To the best of the Company's knowledge, all international operations are in compliance with applicable environmental and safety regulations. Risks of significant costs and liabilities, however, are inherent in the nature of the operations, and there can be no assurances that such costs and liabilities will not be incurred.

Employees

Enbridge International operations directly employ 26 individuals.

CORPORATE

Corporate activities are limited to business development activities not attributable to a specific business segment, corporate financing costs and various support personnel costs. In addition, business activities in the development stage or those that may represent an emerging technology may be included in Corporate. These activities are seen as potential growth areas that may have a strategic fit with existing operations or present the opportunity to enhance activity levels in existing operating segments. Approximately 192 employees are employed in the Corporate segment.

CORPORATE SOCIAL RESPONSIBILITY

Enbridge has in place social and environmental policies that are fundamental to its operations. These policies are collectively referred to as Corporate Social Responsibility (CSR). Enbridge defines CSR as conducting business in a socially responsible and ethical manner, protecting the environment and health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures with which the Company works. CSR covers the Company's involvement in areas such as the environment, safety, corporate governance, human rights, community investment and stakeholder engagement.

Environmental Initiatives

Enbridge's environmental goals include reducing green house gas emissions and emission intensity; reducing the loss of methane from natural gas gathering pipelines; investing in wind power, which is an emissions-free renewable source of energy; promoting the use of natural gas powered vehicles in the Greater Toronto Area and preventing spills and leaks on significant pipeline systems.

Steps taken to implement Enbridge's environmental goals:

- Improving energy efficiency of liquids pipelines, which use significant electricity to transport oil over long distances;
- Replacing older cast iron pipe with polyethylene pipe at EGD to reduce the release of natural gas into the atmosphere;
- Encouraging the efficient use of natural gas by customers at EGD through Demand Side Management programs which include information, audits and financial incentives;
- Promoting renewable energy through the development of wind power projects;
- Measuring and reporting emissions, which the Company has done publicly since 1994;
- Promoting markets for cleaner vehicles through EGD involvement in promoting natural gas vehicles;
- Carrying out spill prevention and maintenance programs; and
- Monitoring and remediating historic leak sites.

Safety Initiatives

Enbridge's safety goals include reducing injury frequency and promoting a healthy and illness-free workplace through regular training and open communication with employees, emphasizing the importance of addressing health and safety risks before serious incidents occur.

Steps taken to implement Enbridge's safety initiatives include:

- Engaging employees through regular meetings of local and regional environmental health and safety (EH&S) committees;
- Conducting regular workplace inspections through EH&S committees;
- Increasing awareness training on hydrogen sulfide; and
- Encouraging personal fitness and increasing health awareness among employees.

Corporate Governance Initiatives

Corporate governance initiatives ensure a comprehensive system of stewardship and accountability is in place and functioning among directors, management and employees.

Steps taken to implement Enbridge's corporate governance initiatives include:

- Requiring every employee and director to follow Enbridge's Statement on Business Conduct;
- Meeting Sarbanes-Oxley requirements as they become applicable to the Company; and
- Assessing the independence of the Board of Directors annually.

Human Rights Initiatives

Enbridge is committed to observing and promoting human rights in its activities. The Company has a 24.7% investment in OCENSA pipeline in Colombia. OCENSA has a human rights policy under which it carries out regular human rights training of employees, contractors and military personnel involved in protecting the pipeline.

Community Investment Initiatives

Community investment initiatives include funding for the arts and health services, organizing local United Way campaigns and creating innovative partnerships with not for profit groups.

Stakeholder Engagement

Stakeholder engagement means developing positive relationships with employees, suppliers, customers, investors, government agencies, environmental groups, business partners and local communities. Initiatives include early-stage project consultation on organic growth projects; public awareness programs on pipeline safety and regular customer surveys at EGD to better understand customer needs.

RISK FACTORS

A discussion of the Company's risk factors is contained in the following subsections of the Management's Discussion and Analysis for the year ended December 31, 2005, which are incorporated herein by reference (the page references below are to the Company's 2005 Management's Discussion and Analysis filed on SEDAR at www.sedar.com):

Liquids Pipelines — Business Risks (page 16);
Gas Pipelines — Business Risks (pages 21 to 23);
Sponsored Investments — Business Risks (pages 26 to 27);
Gas Distribution and Services — Business Risks (pages 35 to 37);
International — Business Risks (page 38);
Overall Risk Management (pages 41 to 44).

DIVIDENDS

DIVIDENDS PAID

(Canadian dollars per share)	**2005**	2004	2003
Preference Shares, Series A	**1.375**	1.375	1.375
Common Shares	**1.038**	0.915	0.830

Dividends on common shares are paid quarterly as determined by the Company's Board of Directors. The Company is targeting to pay out approximately 60% to 70% of earnings as dividends, balancing its future capital reinvestment requirements and investors' preferences for income. Dividends on the preference shares, Series A, are fixed and are paid quarterly.

There are no restrictions that currently prevent the Company from paying dividends. However, in the event of liquidation, dissolution or winding-up of the Company, the preferred shareholders have priority in the payment of dividends over the common shareholders. As well, should the Company fail to make payments on certain financial obligations, the Company could be precluded from paying dividends on its common and preferred shares.

DESCRIPTION OF CAPITAL STRUCTURE

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

At December 31, 2005, the Company's capital structure consists of 348.9 million common shares with a book value of $2,343.8 million and 5.0 million preference shares, Series A with a book value of $125.0 million.

Common Shares

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares. Each common shareholder is entitled to one vote for each share held at all such meetings of shareholders.

Under the dividend reinvestment and share purchase plan, registered shareholders may reinvest their dividends in additional common shares of the Company or make optional cash payments to purchase additional common shares, in either case, free of brokerage or other charges.

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

Preferred Shares

The 5.5% Cumulative Redeemable Preference Shares, Series A are entitled to fixed, cumulative, preferential dividends of $1.375 per share per year, payable quarterly. Preferred shareholders have no voting rights. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.75 per share if redeemed on or prior to December 1, 2005; $25.50 per share if redeemed on or prior to December 1, 2006; $25.25 per share if redeemed on or prior to December 1, 2007; and $25.00 per share if redeemed thereafter, in each case with all accrued and unpaid dividends to the redemption date.

RATINGS

The following table sets forth the ratings assigned to the Company's Preference Shares, Series A, Preferred Securities, Commercial Paper and Unsecured Debt by Dominion Bond Rating Service Limited (DBRS), Standard & Poor's Ratings Services (S&P) and Moody's Investor Services, Inc. (Moody's):

	DBRS	S&P	Moody's
Preference Shares, Series A	Pfd-2 (low)[1]	P-2[3]	Baa2[5]
Preferred Securities	Pfd-2y[1]	BBB[3]	Baa1[5]
Commercial Paper	R-1 (low)[2]	A-1 (low)[4]	Not Rated
Unsecured Debt	A[2]	A-[4]	A3[6]

Notes:

1. DBRS' rating of preferred securities and preferred shares is on a rating scale that ranges from a high of Pfd-1 to a low of Pfd-5. The 'y' modifier is used to indicate a hybrid security. DBRS also applies modifiers 'high', 'medium', and 'low' which indicate where the obligation ranks in its generic rating category.
2. DBRS rates debt instruments by rating categories from a high of 'AAA' to a low of 'C'. DBRS' rating of commercial paper is on a rating scale that ranges from a high of R-1 to a low of D. DBRS applies modifiers 'high', 'medium', and 'low' which indicate where the obligation ranks in its generic rating category.
3. S&P rates preferred shares using categories from a high of 'P-1' to a low of 'P-5'. Preferred securities are rated using a long-term debt rating scale that ranges from a high of 'AAA' to a low of 'D'.
4. S&P rates debt instruments by rating categories from a high of 'AAA' to a low of 'D'. S&P's rating of commercial paper is on a rating scale that ranges from a high of A-1 to a low of C. S&P applies modifiers 'high', 'medium', and 'low', which indicate where the obligation ranks in its generic rating category.
5. Moody's rates securities and shares by rating categories from a high of 'Aaa' to a low of 'C'. Moody's applies modifiers 1, 2 and 3, which indicate where the obligation ranks in its generic rating category. Modifier 1 is higher end, modifier 2 is mid-range and modifier 3 is low end ranking of the generic rating category.
6. Moody's rates debt instruments by rating categories from a high of 'Aaa' to a low of 'C'. Moody's applies modifiers '1', '2' and '3', which indicate where the obligation ranks in its generic rating category. Modifier '1' is higher end, modifier '2' is mid-range and modifier '3' is low end ranking of the generic rating category.

The credit ratings accorded by these rating agencies are not recommendations to purchase, hold or sell the shares or securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

MARKET FOR SECURITIES

As of the date of this Annual Information Form, the common shares of the Company are traded on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the symbol ENB. The Toronto Stock Exchange is the principal market for Enbridge's common shares. The Preference Shares, Series A are traded on the Toronto Stock Exchange under the symbol ENB.PR.A and the preferred securities, series 7.8%, are traded on the Toronto Stock Exchange under the symbol ENB.PR.D.

The following table sets forth the monthly price range and volume traded for each of the Company's publicly traded securities for each month during the most recently completed financial year.

			TSX (C$)			NYSE (US$)
			ENB	ENB.PR.A	ENB.PR.D	ENB
January		High	62.95	26.68	28.03	50.73
		Low	57.18	26.27	27.26	47.05
	31-Jan	Close	62.91	26.42	27.32	50.65
		Volume	13,339,000	39,900	120,300	1,524,000
February		High	64.79	26.67	27.89	52.45
		Low	61.00	25.78	27.21	48.94
	28-Feb	Close	61.19	26.05	27.36	49.63
		Volume	13,571,400	38,800	100,300	1,187,800
March		High	64.36	26.17	27.90	52.76
		Low	59.73	25.50	26.23	48.90
	31-Mar	Close	62.20	25.75	26.38	51.48
		Volume	14,117,000	27,900	95,200	1,354,200
April		High	64.77	25.98	26.96	52.75
		Low	61.40	25.32	26.28	49.60
	29-Apr	Close	63.45	25.40	26.60	50.46
		Volume	11,140,000	59,600	79,200	1,309,400
May		High	66.95	26.00	27.50	54.45
		Low[1]	33.10	25.52	26.46	26.69
	31-May	Close	33.40	25.70	27.15	26.79
		Volume	13,942,700	43,800	75,900	2,145,300
June		High	36.19	26.25	27.24	29.38
		Low	32.77	25.56	26.55	26.27
	30-Jun	Close	34.95	25.77	26.70	28.50
		Volume	12,640,800	38,300	100,100	1,626,300
July		High	36.50	26.12	27.00	29.87
		Low	34.37	25.52	26.60	28.09
	29-Jul	Close	35.30	25.90	27.00	28.84
		Volume	10,300,700	31,500	57,200	1,832,700
August		High	36.60	26.29	26.94	30.28
		Low	33.31	25.53	26.60	27.80
	31-Aug	Close	35.02	25.80	26.66	29.58
		Volume	12,098,800	33,700	72,700	3,299,400
September		High	38.50	26.14	26.89	32.70
		Low	34.60	25.80	26.11	29.22
	30-Sep	Close	37.26	26.00	26.51	31.92
		Volume	13,328,500	31,700	98,200	8,604,400
October		High	37.46	26.11	26.89	32.13
		Low	33.05	25.15	25.66	28.15
	31-Oct	Close	36.01	25.80	26.20	30.69
		Volume	11,539,000	11,200	82,200	3,718,000
November		High	38.82	26.37	26.48	33.11
		Low	35.50	25.64	26.05	29.79
	30-Nov	Close	36.18	26.21	26.32	31.09
		Volume	13,630,000	35,700	89,800	2,579,400
December		High	37.10	26.49	26.75	31.75
		Low	35.30	26.00	26.12	30.54
	30-Dec	Close	36.34	26.14	26.65	31.27
		Volume	10,879,500	124,400	147,500	1,678,200

1. A two-for-one stock split was approved by the Company's shareholders at the May 5, 2005 Annual and Special Meeting, and the Company's shares commenced trading on this basis effective May 18, 2005.

The following table outlines the securities issued by the Company during 2005 that are not listed or quoted on an exchange. These securities are in the form of unsecured medium term note debentures.

Issuer	Principal Amount	Coupon	Issue Date	Maturity Date	Issue Price
Enbridge Inc.	$250 million	3.95%	February 15, 2005	February 15, 2010	$ 99.928
Enbridge Inc.	$150 million	5.57%	November 14, 2005	November 14, 2035	$ 99.870
Enbridge Pipelines Inc.	$250 million	4.46%	December 16, 2005	December 17, 2012	$ 99.988

DIRECTORS AND OFFICERS

DIRECTORS

The following table sets forth the names of the Directors of Enbridge Inc. effective December 31, 2005, unless otherwise noted, their municipalities of residence, their respective principal occupations within the five preceding years and the year from which they first became a Director of the Company. Enbridge does not have an Executive Committee. As required, the Company has an Audit, Finance & Risk Committee.

Name [1] and Municipality of Residence	Principal Occupation for the Five Preceding Years	Year First Became a Director[2]
DAVID A. ARLEDGE[5, 6] Naples, Florida U.S.A.	Corporate Director; Chair of the Board of Directors of Enbridge Inc. since 2005; Director of AmerUS Group Co. (public life insurance company) since October 2002; Director, Realty Group of Naples, L.L.C. since January 2002; Vice Chairman of the Board of Directors of El Paso Corporation (integrated energy company) until November 2001, having served in that capacity since the merger of Coastal Corporation and El Paso Corporation.	2002
JAMES J. BLANCHARD[4, 5] Beverly Hills, Michigan U.S.A.	Senior Partner, DLA Piper Rudnick Gray Cary U.S., LLP (law firm), since 1996; prior thereto, United States Ambassador to Canada.	1999
J. LORNE BRAITHWAITE[4, 6] Malahide, County Dublin, Ireland	Corporate Director; President & Chief Executive Officer of Cambridge Shopping Centres Limited (developer and manager of retail shopping malls in Canada) from 1978 to 2001.	1989
PATRICK D. DANIEL Calgary, Alberta Canada	President & Chief Executive Officer of Enbridge since January 2001; prior thereto, President & Chief Operating Officer of Enbridge since September 2000.	2000
E. SUSAN EVANS[3, 6] Calgary, Alberta Canada	Corporate Director.	1996
WILLIAM R. FATT[3, 6] Toronto, Ontario Canada	Chief Executive Officer of Fairmont Hotels & Resorts Inc. since September 2001; prior thereto, Chairman & Chief Executive Officer of Canadian Pacific Hotels & Resorts Inc. since January 1998.	2000

Name [1] and Municipality of Residence	Principal Occupation for the Five Preceding Years	Year First Became a Director[2]
LOUIS D. HYNDMAN[3, 4] Edmonton, Alberta Canada	Counsel, Field Law LLP (law firm) since 2005; prior thereto, Senior Partner Field Law LLP.	1993
DAVID A. LESLIE[3, 5] Toronto, Ontario Canada	Corporate Director; Chairman and Chief Executive Officer of Ernst & Young LLP from 1999 to 2004.	2005
ROBERT W. MARTIN[3, 6, 7] Toronto, Ontario Canada	Corporate Director.	1992
GEORGE K. PETTY[4, 5] San Luis Obispo, California U.S.A.	Corporate Director; President & Chief Executive Officer of Telus Corporation (telecommunications company) from 1994 to 1999.	2001
CHARLES E. SHULTZ[5, 6] Calgary, Alberta Canada	Chairman & Chief Executive Officer of Dauntless Energy Inc. (private oil and gas corporation) since 1995; Chairman of Canadian Oil Sands Limited (a subsidiary of Canadian Oil Sands Trust, a public oil and gas trust).	2004
DONALD J. TAYLOR[5, 6] Jacksons Point, Ontario Canada	Corporate Director; Chair of the Board of Directors of Enbridge Inc. from 1996 to 2005.	1979

Notes:

1. Each Director elected holds office until the next annual meeting of shareholders or until a successor is duly elected or appointed.
2. "Year First Became a Director" refers to the year the person named was elected or appointed as a Director of the Company or of its predecessor parent, Interprovincial Pipe Line Inc.
3. Member of the Audit, Finance & Risk Committee of the Board of Directors.
4. Member of the Corporate Social Responsibility Committee of the Board of Directors.
5. Member of the Governance Committee of the Board of Directors.
6. Member of the Human Resources & Compensation Committee of the Board of Directors.
7. On December 2, 2003, the Ontario Securities Commission (the "Commission") issued a temporary cease trade order against Atlas Cold Storage Income Trust ("Atlas"), and subsequently a cease trade order on December 15, 2003, after Atlas failed to file its interim financial statements for its nine-month period ended September 30, 2003. Under such orders, certain trustees, including Mr. Martin, were prohibited from trading Atlas trust units until the Commission was in receipt of the necessary filings. Atlas made the requisite filings on January 27, 2004 and the cease trade order lapsed on February 2, 2004.

OFFICERS

The following table sets forth the names of the senior executive officers, their current office with the Company effective December 31, 2005, unless otherwise noted, their municipality of residence and their principal occupations for the five preceding years.

Name, Position and Municipality of Residence	Position and Principal Occupations for the Five Preceding Years
PATRICK D. DANIEL President & Chief Executive Officer Calgary, Alberta Canada	President & Chief Executive Officer since January 2001; prior thereto, President & Chief Operating Officer from September to December 2000.
MEL F. BELICH Group Vice President, Corporate Law Calgary, Alberta Canada	Group Vice President, Corporate Law since May 2005; prior thereto, Group Vice President, International & Corporate Law since April 2003; prior thereto, Group Vice President, International since September 2000.
J. RICHARD BIRD Group Vice President, Liquids Pipelines Calgary, Alberta Canada	Group Vice President, Liquids Pipelines since May 2005; prior thereto, Group Vice President, Transportation North since May 2001; prior thereto, Group Vice President, Transportation since September 2000.
BONNIE D. DUPONT Group Vice President, Corporate Resources Calgary, Alberta Canada	Group Vice President, Corporate Resources since September 2000.
STEPHEN J.J. LETWIN Group Vice President, Gas Strategy & Corporate Development Calgary, Alberta Canada	Group Vice President, Gas Strategy & Corporate Development since April 2003; prior thereto, Group Vice President, Distribution & Services since September 2000.
DAN C. TUTCHER Group Vice President, Transportation South Houston, Texas U.S.A.	Group Vice President, Transportation South since May 2001; prior thereto, Chairman of the Board, President & Chief Executive Officer of Midcoast Energy Resources, Inc. since 1992.
STEPHEN J. WUORI Group Vice President & Chief Financial Officer Calgary, Alberta Canada	Group Vice President & Chief Financial Officer since April 2003; prior thereto, Group Vice President, Planning & Development since September 2000.
JAMES A. SCHULTZ Senior Vice President Gormley, Ontario Canada	Senior Vice President since April 2003; President of Enbridge Gas Distribution Inc. (EGDI) since June 2001; prior thereto, Vice President, Operations and Engineering, EGDI, since July 1999.
AL MONACO Senior Vice President, Planning & Development Calgary, Alberta Canada	Senior Vice President, Planning & Development since June 2003; prior thereto, Vice President, Financial Services since February, 2002; prior thereto, Director, Financial Services since 2000; prior thereto, Director, Investor Relations.

As at December 31, 2005, the directors and officers of the Issuer beneficially owned, directly or indirectly, 1,317,309 common shares of the Issuer, representing approximately 3.77% of the issued and outstanding common shares on that date. The information as to shares beneficially owned or over which control or direction is exercised, not being within the knowledge of the Issuer, has been furnished by the respective directors and officers individually. The directors and officers do not beneficially own, directly or indirectly, any voting securities of any subsidiary of the Issuer.

AUDIT, FINANCE & RISK COMMITTEE — FURTHER INFORMATION

GENERAL INFORMATION

Enbridge is required by law to have an audit committee and to disclose certain information concerning that committee pursuant to Multilateral Instrument 52-110 (MI 52-110).

The Board has established the Audit, Finance & Risk Committee (the AFR Committee), comprised of five members: Robert W. Martin (Chair), E. Susan Evans, William R. Fatt, Louis D. Hyndman and David A. Leslie. The Board has determined that each of the members is "independent" and "financially literate", within the meaning of MI 52-110.

MANDATE

The AFR Committee's Terms of Reference are attached to this annual information form as Appendix A.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The following is a brief summary of the education or experience of each member of the AFR Committee that is relevant to the performance of his or her responsibilities as a member of the AFR Committee, including any education or experience that has provided the member with, among other things, an understanding of the accounting principles used by Enbridge to prepare its annual and interim financial statements.

Robert W. Martin

Mr. Martin acquired significant financial experience and exposure to accounting and financial issues as President, Chief Executive Officer and director of various corporations and in various finance positions. He was the President and Chief Executive Officer of Consumers Gas Company (now Enbridge Gas Distribution Inc.) where he was responsible for all financial aspects related to that corporation. He has acted as a member and Chair of other audit committees, and currently serves as Chair of the audit committee of HSBC Bank of Canada.

E. Susan Evans

Mrs. Evans, a lawyer, has over 25 years experience in corporate and legal matters first in private practice with a large Calgary law firm and then as a lawyer and officer of several public companies. She is currently a director and member of the audit committee of Canadian Oil Sands Limited. She previously served as Chair of the audit committee for the Province of Alberta and Commissioner of the Alberta Financial Review Commission. She has sat on several audit committees including those of Canada Deposit Insurance Company, Home Oil, Anderson Exploration, and Citizens Bank.

William R. Fatt

Mr. Fatt has over 30 years of financial experience gained through working for several large Canadian public companies, including as Chief Financial Officer of Canadian Pacific Limited. He is the Chief Executive Officer of Fairmont Hotels and Resorts Inc. Mr. Fatt held the offices of Chair, Chief Executive Officer and

Chief Financial Officer at Canadian Pacific Hotels and Resorts Inc. He was also a director and member of the audit committee of EnCana Corporation.

Louis D. Hyndman

Mr. Hyndman, a lawyer, is counsel at Field Law LLP where he was formerly a senior partner. He was a member of the audit committee of Canada Trust and was the Chair of the audit committee of Oxford Properties Group Inc. From 1979 to 1986, Mr. Hyndman served as Alberta's provincial treasurer.

David A. Leslie, F.C.A.

Mr. Leslie is a chartered accountant and in his career of over 30 years, he was, among other things, personally involved in, and actively supervised persons engaged in, preparing, auditing, analyzing and evaluating financial statements. He is the former Chairman and Chief Executive Officer of Ernst & Young LLP. He is also a director and member of the audit committee of Sobeys Inc.

EXEMPTIVE RELIEF

Mr. Martin's son is a partner of PricewaterhouseCoopers LLP ("PWC"). As PWC are the auditors of the Corporation, there was a period of time from May 5, 2005 (being the date upon which MI 52-110 became applicable to the Company) to June 30, 2005 (the date on which certain amendments to MI 52-110 came into force) during which Mr. Martin was not considered "independent" for the purposes of MI 52-110 as the provisions of MI 52-110 in force at that time deemed Mr. Martin to have a material relationship with the Corporation because of his son's relationship with PWC. The Company made an application to the Alberta Securities Commission for exemptive relief from the applicable provisions, which application was successful and an exemptive relief order was granted. When the amendments to MI 52-110 came into force on June 30, 2005, Mr. Martin was no longer deemed to have a material relationship with PWC, and is now considered to be "independent" for the purposes of MI 52-110.

PRE-APPROVAL POLICIES AND PROCEDURES

On October 30, 2003, the AFR Committee adopted a policy that requires pre-approval by the Committee of any services to be provided by the auditors, whether audit and non-audit services. The policy prohibits the Company from engaging the auditors to provide the following non-audit services:

(a) bookkeeping or other services related to accounting records and financial statements;

(b) financial information systems design and implementation;

(c) appraisal or valuation services, fairness opinions, or contribution-in-kind reports;

(d) actuarial services;

(e) internal audit outsourcing services;

(f) management functions or human resources;

(g) broker or dealer, investment adviser, or investment banking services;

(h) legal services; and

(i) expert services unrelated to the audit.

The AFR Committee believes that the policy will protect the Company from the potential loss of independence of the external auditors.

A copy of the policies and procedures on the pre-approval of non-audit services by the Company's auditors may be obtained from the Corporate Secretary of the Company by sending a written request to #3000, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8, by faxing a written request to (403) 231-5929, by calling (403) 231-3900 or by sending an e-mail to **corporatesecretary@enbridge.com.**

The AFR Committee has also adopted a policy which prohibits the Company from hiring former employees of the auditors who provided more than 10 hours of audit, review or attest services for the Company or its subsidiaries within the one year preceding the commencement of the audit of the current year's financial statements.

EXTERNAL AUDITOR SERVICES — FEES

The following table sets forth all services rendered by the auditors (PWC) by category, together with the corresponding fees billed by the auditors for each category of service for the financial years ended December 31, 2004 and 2005.

	Years ended December 31	
	2005	**2004**
Audit Fees [1]	**$ 1,658,869**	$ 1,096,423
Audit-Related Fees [2]	**166,552**	1,660,155
Tax Fees [3]	**210,490**	166,801
All Other Fees [4]	**32,360**	80,063
Total Fees	**$ 2,068,271**	$ 3,003,442

Notes:

(1) Represents the aggregate fees billed by the Corporation's auditors for audit services.

(2) Represents the aggregate fees billed for assurance and related services by the Corporation's auditors that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not included under "Audit Fees". This amount includes $1,280,000 for Sarbanes-Oxley Act related procedures in 2004.

(3) Represents the aggregate fees billed for professional services rendered by the Corporation's auditors for tax compliance, tax advice and tax planning.

(4) Represents the aggregate fees billed for products and services provided by the Corporation's auditors other than those services reported under "Audit Fees", "Audit Related Fees" and "Tax Fees".

LEGAL PROCEEDINGS

The information, which is found under note 24 "Commitments and Contingencies" of the Company's audited consolidated financial statements, as at, and for the year ended, December 31, 2005, is incorporated by reference herein.

REGISTRAR AND TRANSFER AGENT

The registrar and transfer agent for the common shares is CIBC Mellon Trust Company at its principal offices in Vancouver, British Columbia; Calgary, Alberta; Winnipeg, Manitoba; Toronto, Ontario; Montreal, Quebec; and Halifax, Nova Scotia. The co-registrar and co-transfer agent in the United States for the common shares is Mellon Investor Services at its principal office in Ridgefield Park, New Jersey.

The registrar and transfer agent for the Preference Shares, Series A is CIBC Mellon Trust Company at its principal offices in Vancouver, British Columbia; Calgary, Alberta; Winnipeg, Manitoba; Toronto, Ontario; Montreal, Quebec; and Halifax, Nova Scotia.

The registrar and transfer agent for the Preferred Securities, Series D is Computershare Trust Company of Canada at its principal office in Calgary, Alberta.

INTERESTS OF EXPERTS

The consolidated financial statements of the Company, as at and for the years ended December 31, 2005, 2004 and 2003, have been examined by PWC, as detailed in their auditors' report dated February 1, 2006.

PWC is independent of the Company in accordance with the auditor's rules of professional conduct in Canada.

ADDITIONAL INFORMATION

Additional information, including Directors' and Officers' remuneration and indebtedness, principal holders of the Company's securities and options to purchase Enbridge's securities, and the interest of insiders in material transactions, all as at December 31, 2005, is contained in Enbridge's Management Information Circular dated March 3, 2006 furnished in connection with the Annual and Special Meeting of Shareholders to be held on May 3, 2006 for the purpose of, among other things, the election of directors. Additional financial information is provided in the Company's comparative financial statements and management's discussion and analysis for the year ended December 31, 2005. Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Effective Date

Unless otherwise specifically herein provided, the information contained in this Annual Information Form is stated effective as at December 31, 2005.

TERMS OF REFERENCE FOR THE
AUDIT, FINANCE & RISK COMMITTEE

I. CONSTITUTION

There shall be a committee, to be known as the Audit, Finance & Risk Committee (the "Committee"), of the Board of Directors of Enbridge Inc.

II. MEMBERSHIP

Following each annual meeting of shareholders of the Corporation, the Board shall elect from its members, not less than three (3) Directors to serve on the Committee (the "Members"). The Members and the Chair of the Committee are elected by the Board following the nomination of Directors by the Governance Committee. No Member of the Committee shall be an officer or employee of the Corporation or any of the Corporation's affiliates. All members of the Committee shall, in the judgment of the Board, be unrelated and independent and shall satisfy applicable stock exchange and legal requirements. Determinations on whether a Director meets the requirements for membership on the Committee shall be made by the Board. At least one member of the Committee shall be a "financial expert" as determined by the Board and as defined by American legal or regulatory requirements. No Director may serve as a member of the Committee if such Director also serves on the audit committees of more than two other public entities unless the Board determines that such simultaneous service would not impair the ability of such Director to effectively serve on the Committee.

Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of the Corporation. Each Member shall hold office until the close of the next annual meeting of Shareholders of the Corporation or until the Member ceases to be a Director, resigns or is replaced, whichever first occurs. Vacancies may be filled by the Board with nominees approved by the Governance Committee.

III. MEETINGS

The Committee shall convene at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, an officer, the internal auditor or the external auditors of the Corporation. A minimum of twenty-four (24) hours notice of each meeting shall be given to each Member and to the internal and external auditors.

A majority of the committee shall be duly convened if all Members are present, or at least a majority of the Members are present. A quorum at a meeting shall consist of at least a majority of Members. Where the Members consent, and proper notice has been given or waived, Members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting.

In the absence of the Chair of the Committee, the Members may choose one (1) of the Members to be the Chair of the meeting.

At the invitation of a Member, other Board members, officers or employees of the Corporation, the external auditors, external counsel and other experts or consultants may attend any meeting of the Committee.

Members of the Committee may meet separately with any member of management, the external auditors, the internal auditor, internal or external counsel or any other expert or consultant.

Minutes shall be kept of all meetings of the Committee.

IV. FUNDING

The Corporation shall provide appropriate funding, as determined by the Committee, for the payment of compensation to the external auditors and any independent counsel, experts or advisors employed by the Committee and administrative expenses of the Committee.

V. REVIEW OF CHARTER

The Committee shall review and reassess the adequacy of its Terms of Reference at least annually and propose recommended changes to the Board.

VI. DUTIES AND RESPONSIBILITIES OF THE CHAIR

The Chair is responsible for:

A. convening Committee meetings and designating the times and places of those meetings;

B. ensuring Committee meetings are duly convened and that quorum is present when required;

C. working with Management on the development of agendas and related materials for the Committee meetings;

D. ensuring Committee meetings are conducted in an efficient, effective and focused manner;

E. ensuring the Committee has sufficient information to permit it to properly make decisions when decisions are required;

F. providing leadership to the Committee and to assist the Committee in reviewing and monitoring its responsibilities; and

G. reporting to the Board on the recommendations and decisions of the Committee.

VII. DUTIES AND RESPONSIBILITIES

The Committee provides assistance to the Board in fulfilling its oversight responsibility to the shareholders, the investment community and others, relating to the integrity of the Corporation's financial statements and the financial reporting process, the management information systems and financial controls, the internal audit function, the external auditors' qualifications, independence, performance and reports, the Corporation's compliance with legal and regulatory requirements and the risk identification, assessment and management program. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between the Committee, the external auditors, the internal auditors and management of the Corporation.

Management is responsible for preparing the interim and annual financial statements and financial disclosure of the Corporation and for maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly. The Committee's role is to provide meaningful and effective oversight and counsel to management without assuming responsibility for management's day-to-day duties.

In performance of its duties and responsibilities, the Committee shall have the right as it determines necessary to carry out its duties to engage independent counsel, experts and other advisors, to inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates, and to discuss with the officers of the Corporation, its subsidiaries and affiliates, the internal auditor and the external auditors, such accounts, records and other matters as any Member considers appropriate.

The Committee shall have the following specific duties and responsibilities:

A. DUTIES AND RESPONSIBILITIES RELATED TO THE EXTERNAL AUDITORS.

The Committee shall:

(i) (a) be responsible for the appointment, compensation, oversight, retention and termination of the external auditors who shall report directly to the Committee, provided that the appointment of the auditor shall be subject to shareholder approval; and

(b) be responsible for the appointment, compensation, oversight, retention and termination of any other registered public accounting firm for audit, review or attestation services;

(ii) review and approve the terms of the external auditors' annual engagement letter, including the proposed audit fees;

(iii) review and approve all engagements for audit services and non-audit services to be provided by the external auditors and, as necessary,

consider the potential impact of such services on the independence of the external auditors;

(iv) review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence;

(v) at least annually, obtain and review a report by the external auditors describing the firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditors and any steps taken to deal with any such issues and all relationships between the external auditors and the Corporation;

(vi) resolve disagreements, if any, between management and the external auditors regarding financial reporting;

(vii) inform the external auditors and management that the external auditors shall have access directly to the Committee at all times, as well as the Committee to the external auditors and that the external auditors are ultimately accountable to the Committee as representatives of the shareholders of the Corporation;

(viii) discuss with management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies; and

(ix) establish hiring policies for employees or former employees of the external auditors.

B. DUTIES AND RESPONSIBILITIES RELATED TO AUDITS AND FINANCIAL REPORTING.

The Committee shall:

(i) review the engagement terms and the audit plan with the external auditors and with the Corporation's management;

(ii) review with management and the Corporation's external auditors the Corporation's financial reporting in connection with the annual audit and the preparation of the financial statements, including, without limitation, the judgment of the external auditors as to the quality, not just the acceptability of, and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or

conservatism of the Corporation's accounting principles and underlying estimates;

(iii) review with management and the external auditors and make recommendations to the Board on all financial statements and financial disclosure which require approval by the Board including:

(a) the Corporation's annual financial statements including the notes thereto and "Management's Discussion and Analysis";

(b) any report or opinion to be rendered in connection therewith;

(c) any change or initial adoption in accounting policies and their applicability to the business;

(d) any audit problems or difficulties and management's response;

(e) all significant adjustments proposed by the external auditors; and

(f) satisfying itself that there are no unresolved issues between management and the external auditors that could reasonably be expected to materially affect the financial statements.

(iv) review the Corporation's interim financial results, including the notes thereto and "Management's Discussion and Analysis" with management and the external auditors and approve the release thereof by management or recommend approval thereof to the Board for release by the Board;

(v) review annually the approach taken by management in the preparation of earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies;

(vi) discuss with the external auditors their perception of the Corporation's internal audit and accounting personnel, and any recommendations which the external auditors may have;

(vii) review with management, the external auditors and, as necessary, internal and external legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(viii) review with management and monitor the funding exposure of the Corporation under the Corporation's pension plans and review annually the annual report and financial statements applicable to each of the pension plans;

(ix) annually or more frequently as deemed necessary, meet separately with management and the external auditors, and at least annually with the

internal auditors, to review issues and matters of concern respecting audits and financial reporting processes;

(x) review with the Corporation's management and, as deemed necessary, review with the external auditors, any proposed changes in or initial adoption of accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of the Corporation's management that may be material to financial reporting;

(xi) review with the Corporation's management and, as deemed necessary, with the external auditors, significant financial reporting issues arising during the fiscal period, including the methods of resolution;

(xii) review any problems experienced by the external auditors in performing an audit, including any restrictions imposed by the Corporation's management or significant accounting issues on which there was a disagreement with the Corporation's management;

(xiii) review the post-audit or management letter containing the recommendations of the external auditors and the response of the Corporation's management, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation (in respect of the scope of review of internal controls by the external auditors, the review is carried out to enable the external auditors to express an opinion on the Corporation's financial statements);

(xiv) review before release relevant public disclosure documents containing audited or unaudited financial information, including annual and interim earnings press releases, prospectuses, the Annual Information Form, and the Management's Discussion and Analysis disclosure;

(xv) review, in conjunction with the Human Resources & Compensation Committee, the appointment of the chief financial officer;

(xvi) inquire into and determine the appropriate resolution of conflicts of interest in respect of audit, finance or risk matters between or among an officer, Director, shareholder, the internal auditors, or the external auditors, which are properly directed to the Committee by the Chair of the Board, the Board, a shareholder, the internal auditors, the external auditors, or the Corporation's management; and

(xvii) as deemed necessary by the Committee, inquire into and examine matters relating to the financial affairs of the Corporation, its subsidiaries or affiliates, or any of them, including the review of subsidiary or affiliate Audit Committee reports.

C. DUTIES AND RESPONSIBILITIES RELATED TO FINANCIAL REPORTING PROCESSES AND INTERNAL CONTROLS

The Committee shall:

(i) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors, management, and the internal auditor;

(ii) review with management the Corporation's administrative, operational and accounting internal controls, including controls and security of the computerized information systems, and evaluate whether the Corporation is operating in accordance with prescribed policies, procedures and the Statement on Business Conduct;

(iii) annually or more frequently if deemed necessary, meet separately with the external auditor, the head of the internal audit group and management, to review issues and matters of concern respecting financial reporting processes and internal controls;

(iv) review with management and the external auditors any reportable conditions, material weaknesses and significant deficiencies affecting internal control;

(v) establish and maintain free and open means of communication between and among the Committee, the external auditors, the internal auditor and management;

(vi) review at least annually with the internal auditor the Corporation's internal control procedures, and the scope and plans for the work of the internal audit group; and

(vii) review the adequacy of resources of the internal auditor and ensure that the internal auditor has unrestricted access to all functions, records, property and personnel of the Corporation and inform the internal auditors and management that the internal auditors shall have unfettered access directly to the Committee at all times, as well as the Committee to the internal auditors.

D. DUTIES AND RESPONSIBILITIES RELATED TO FINANCE.

The Committee shall:

(i) review and as required, approve or recommend for approval to the Board, prospectuses and documents, where practicable, which may be incorporated by reference into a prospectus;

(ii) review the issuance of equity or debt securities by the Corporation, and if deemed appropriate, authorize the filing with securities regulatory authorities of any prospectus, prospectus supplement or other documentation relating thereto; and

(iii) review and recommend for approval to the Board the annual management information circular with respect to matters related to the auditor, affecting the capital of the Corporation or principal risks to be managed by the Corporation.

E. DUTIES AND RESPONSIBILITIES RELATED TO RISK MANAGEMENT

The Committee shall:

(i) review at least annually with senior management, internal counsel and, as necessary, external counsel and the Corporation's internal and external auditors:

(a) the Corporation's method of reviewing major risks inherent in the Corporation's businesses, facilities, and strategic directions, including the Corporation's risk management and evaluation process (in respect of risk management evaluations and guidelines relating to environment, health and safety matters, the Committee shall consult with and, as deemed necessary, review the recommendations of the Environment, Health & Safety Committee);

(b) the strategies and practices applicable to the Corporation's assessment, management, prevention and mitigation of risks (including the foreign currency and interest rate risk strategies, counterparty credit exposure, the use derivative instruments, insurance and adequacy of tax provisions);

(c) the Corporation's annual insurance report including the risk retention philosophy and resulting uninsured exposure, if any,

(d) the loss prevention policies, risk management programs, disaster response and recovery programs, corporate liability protection programs for Directors and officers, and standards and accountabilities of the Corporation in the context of competitive and operational considerations.

F. OTHER DUTIES OF AUDIT, FINANCE & RISK COMMITTEE

The Committee shall, as required, or as deemed necessary by the Committee:

(i) review senior management's expense report summaries of the officers and Directors of the Corporation, and review senior management's report summaries concerning corporate aircraft usage;

(ii) meet separately with senior management, the internal auditors, the external auditors and, as is appropriate, internal and external legal counsel and independent advisors in respect of issues not elsewhere listed concerning any other audit, finance and risk matters;

(iii) review incidents or alleged incidents as reported by senior management, audit services, the external auditor, the Corporate Secretary, the law department, or otherwise of fraud, illegal acts and conflicts of interest;

(iv) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

(v) report to the Board after each Committee meeting, as required during the year, with respect to the Committee's activities and recommendations;

(vi) address any other matter properly referred to the Committee by the Chair of the Board, the Board, a Director, the internal auditors, the external auditors, the CEO, or the management of the Corporation or any other matter as may be required under stock exchange rules or by law;

(vii) in conjunction with the Governance Committee, conduct an annual performance evaluation of the Committee; and

(viii) the Committee shall, in conjunction with Management, coordinate the performance of its duties concerning:

(a) the external auditor;

(b) audits and financial reporting;

(c) financial reporting processes and internal controls;

(d) finance; and

(e) risk management

(f) with any audit committee of a subsidiary corporation, respecting the independence of such subsidiary directors and managing to ensure efficiency, effectiveness and consistency of approach with such subsidiary.

VIII. COMMITTEE TIMETABLE

The major annual activities of the Committee shall be outlined in an annual schedule.

IX. DELEGATION TO SUBCOMMITTEE

The Committee may, in its discretion, delegate all or a portion of its duties and responsibilities to a subcommittee of the Committee. The Committee may, in its discretion, delegate to one or more of its members the authority to pre-approve any audit or non-audit services to be performed by the external auditors, provided that any such approvals are presented to the Committee at its next scheduled meeting.

Exhibit 99.4

ENBRIDGE INC.

Consolidated Financial Statements

December 31, 2005

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per share amounts) **Year ended December 31,**	**2005**	2004	2003
Revenues			
Commodity sales	**6,193.5**	5,826.3	3,941.3
Transportation	**1,938.1**	1,695.8	1,560.6
Energy services	**321.5**	285.7	227.1
	8,453.1	7,807.8	5,729.0
Expenses			
Commodity costs	**5,728.4**	5,184.3	3,593.8
Operating and administrative	**1,057.6**	1,015.0	800.8
Depreciation and amortization	**575.3**	525.0	443.0
	7,361.3	6,724.3	4,837.6
	1,091.8	1,083.5	891.4
Income from Equity Investments (Note 9)	**116.8**	160.3	172.8
Other Investment Income (Note 21)	**114.8**	101.4	35.4
Gain on Disposal of Assets (Note 5)	**—**	121.5	239.9
Interest Expense (Note 13)	**(539.2)**	(525.3)	(492.8)
	784.2	941.4	846.7
Income Taxes (Note 19)	**(221.3)**	(289.2)	(172.6)
Earnings	**562.9**	652.2	674.1
Preferred Share Dividends (Note 16)	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**556.0**	645.3	667.2
Earnings Per Common Share (Note 16)	**1.65**	1.93	2.02
Diluted Earnings Per Common Share (Note 16)	**1.63**	1.91	2.00

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions of Canadian dollars, except per share amounts) **Year ended December 31,**	**2005**	2004	2003
Retained Earnings at Beginning of Year	**1,840.9**	1,511.4	1,128.1
Earnings Applicable to Common Shareholders	**556.0**	645.3	667.2
Common Share Dividends	**(361.1)**	(315.8)	(283.9)
Dividends Paid to Reciprocal Shareholders	**11.2**	—	—
Dividend Reclassification Adjustment (Note 9)	**51.2**	—	—
Retained Earnings at End of Year	**2,098.2**	1,840.9	1,511.4
Dividends Paid Per Common Share	**1.04**	0.92	0.83

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars) **Year ended December 31,**	**2005**	2004	2003
Cash Provided By Operating Activities			
Earnings	**562.9**	652.2	674.1
Depreciation and amortization	**575.3**	525.0	443.0
Equity earnings less than/(in excess of) cash distributions	**63.3**	(39.2)	(22.1)
Gain on disposal of assets to Enbridge Income Fund	**—**	—	(239.9)
Gain on reduction of ownership interest	**(29.0)**	(29.6)	(50.0)
Gain on disposal of investment in AltaGas Income Trust	**—**	(121.5)	—
Writedown of EGD regulatory receivable	**—**	—	26.0
Future income taxes	**108.1**	12.7	85.8
Other	**20.3**	28.2	21.4
Changes in operating assets and liabilities (Note 22)	**(397.4)**	(141.1)	(569.8)
	903.5	886.7	368.5
Investing Activities			
Acquisitions (Note 6)	**(88.6)**	(833.9)	(78.3)
Long-term investments	**(89.9)**	(16.6)	(50.5)
Additions to property, plant and equipment	**(680.6)**	(496.4)	(391.3)
Proceeds on redemption of Enbridge Commercial Trust preferred units	**—**	—	24.9
Sale of investment in AltaGas Income Trust (Note 5)	**—**	346.7	—
Sale of assets to Enbridge Income Fund (Note 5)	**—**	—	331.2
Affiliate loans	**0.7**	—	427.2
Change in construction payable	**25.4**	0.5	(3.7)
	(833.0)	(999.7)	259.5
Financing Activities			
Net change in short-term borrowings and short-term debt	**(125.1)**	738.0	359.8
Net change in non-recourse short-term debt of joint ventures	**11.0**	—	—
Long-term debt issues	**1,020.1**	500.0	150.0
Long-term debt repayments	**(536.9)**	(450.0)	(725.0)
Non-recourse long-term debt issued by joint ventures	**6.8**	—	538.3
Non-recourse long-term debt repaid by joint ventures	**(85.1)**	(42.9)	(663.8)
Changes in non-controlling interests	**1.4**	(2.4)	(4.0)
Preferred securities redeemed	**—**	(350.0)	—
Common shares issued	**53.7**	44.4	70.9
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common share dividends	**(361.1)**	(315.8)	(283.9)
	(22.1)	114.4	(564.6)
Increase in Cash and Cash Equivalents	**48.4**	1.4	63.4
Cash and Cash Equivalents at Beginning of Year	**105.5**	104.1	40.7
Cash and Cash Equivalents at End of Year	**153.9**	105.5	104.1

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of Canadian dollars) **December 31,**	**2005**	2004
ASSETS		
Current Assets		
Cash and cash equivalents	**153.9**	105.5
Accounts receivable and other	**1,900.3**	1,451.9
Inventory	**1,021.4**	791.6
	3,075.6	2,349.0
Property, Plant and Equipment, net (Note 7)	**10,466.6**	9,066.5
Long-Term Investments (Note 9)	**1,842.8**	2,278.3
Receivable from Affiliate (Note 23)	**177.0**	171.7
Deferred Amounts and Other Assets (Note 10)	**894.2**	729.2
Intangibles (Note 11)	**252.6**	133.9
Goodwill (Note 12)	**367.2**	31.5
Future Income Taxes (Note 19)	**134.9**	145.0
	17,210.9	14,905.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	**1,074.8**	650.6
Accounts payable and other	**1,624.8**	1,275.9
Interest payable	**81.7**	83.8
Current maturities and short-term debt (Note 13)	**401.2**	703.9
Current portion of non-recourse long-term debt (Note 14)	**68.2**	30.2
	3,250.7	2,744.4
Long-Term Debt (Note 13)	**6,279.1**	6,053.3
Non-Recourse Long-Term Debt (Note 14)	**1,619.9**	665.2
Other Long-Term Liabilities	**91.7**	151.8
Future Income Taxes (Note 19)	**1,009.0**	797.3
Non-Controlling Interests (Note 15)	**691.0**	514.9
	12,941.4	10,926.9
Shareholders' Equity		
Share capital		
Preferred shares (Note 16)	**125.0**	125.0
Common shares (Note 16)	**2,343.8**	2,282.4
Contributed surplus (Note 17)	**10.0**	5.4
Retained earnings	**2,098.2**	1,840.9
Foreign currency translation adjustment	**(171.8)**	(139.8)
Reciprocal shareholding (Note 9)	**(135.7)**	(135.7)
	4,269.5	3,978.2
Commitments and Contingencies (Note 24)	**17,210.9**	14,905.1

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

Approved by the Board:

David A. Arledge
Chair

Robert W. Martin
Director

ENBRIDGE INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Inc. (Enbridge or the Company) is one of North America's largest energy transportation and distribution companies. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Sponsored Investments, Gas Distribution and Services, and International. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

Liquids Pipelines

Liquids Pipelines includes the operation of the Canadian common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons.

Gas Pipelines

Gas Pipelines consists of proportionately consolidated investments in pipelines that transport natural gas including the U.S. portion of the Alliance Pipeline, Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

Sponsored Investments

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) and Enbridge Income Fund (EIF). The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. EIF is a publicly traded income fund whose primary operations include a 50% interest in the Canadian portion of the Alliance Pipeline and a 100% interest in a crude oil and liquids pipeline and gathering system.

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. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, and the Company's proportionately consolidated investment in Aux Sable, a natural gas fractionation and extraction business.

The Company's commodity marketing businesses are also included in Gas Distribution and Services.

International

The Company's International business consists of two investments in energy delivery projects outside of North America.

1. SUMMARY O F SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 26. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the financial statements. Actual results could differ from these estimates.

Basis of Presentation

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. EIF is consolidated in the accounts of the Company as it is a variable interest entity. The Company is the primary beneficiary of EIF through a combination of the 41.9% equity interest and a preferred unit interest. Other investments are accounted for using the cost method.

The Company's gas distribution activities within Gas Distribution and Services are conducted primarily through a wholly-owned subsidiary, Enbridge Gas Distribution Inc. (EGD). In 2004, EGD changed its fiscal year end to December 31, and accordingly, the Company's financial statements for the year ended December 31, 2004 include 15 months of results for EGD and other gas distribution subsidiaries. Prior to 2004, the fiscal year-end of EGD and certain other gas distribution subsidiaries was September 30 and their results were consolidated on a one quarter lag basis. In respect of 2003, references to "December 31" mean the financial position of EGD as at September 30 and references to the "year ended December 31" mean the results of EGD for the year ended September 30.

Regulation

Certain of the Company's Liquids Pipelines, Gas Pipelines, and Gas Distribution and Services businesses are subject to regulation by various authorities, including the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy and Utilities Board (AEUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, agreements with customers and the underlying accounting practices. In order to recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Revenue Recognition

Generally, revenues are recorded when products have been delivered or services have been performed.

However, certain of the operations within Liquids Pipelines, Gas Pipelines and gas distribution operations within Gas Distribution and Services are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts.

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

For rate-regulated operations in Gas Pipelines and Sponsored Investments, transportation revenues include amounts related to expenses recognized in the financial statements that are expected to be recovered from shippers in future tolls. No revenue is recognized in a given period for tolls received that do not relate to current period expenses. Differences between the recorded transportation revenue and actual toll receipts give rise to receivable or payable balances.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the OEB. This may result in the recognition of regulatory assets and liabilities. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

Income Taxes

The regulated activities of the Company recover income tax expense based on the taxes payable method when prescribed by regulators for ratemaking purposes or when stipulated in ratemaking agreements. Therefore, rates do not include the recovery of future income taxes related to temporary differences. Consequently, the taxes payable method is followed for accounting purposes as the Company expects that all future income taxes will be recovered in rates when they become payable.

For all other operations, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are determined based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

Foreign Currency Translation

The Company has U.S. dollar operations, which are primarily self-sustaining except for certain financing and investing operations. The Company also holds a self-sustaining Euro equity investment in a foreign operation in Spain.

The self-sustaining operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using average rates for the period. Gains and losses arising on translation of these operations are included as a separate component of shareholders' equity.

The remaining foreign operations of the Company, including certain financing and investing operations, are integrated with those of the parent company and are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect on the dates the assets were acquired or liabilities were incurred. Revenues and expenses are translated at rates of exchange prevailing on the transaction dates. Under this method, gains and losses on translation are reflected in income when incurred.

Cash and Cash Equivalents

Cash and cash equivalents are recorded at cost and include short-term deposits with a term to maturity of three months or less when purchased.

Inventory

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the prevailing prices approved by the OEB in the determination of customer sales rates. The actual price of gas purchased may differ from the OEB-approved price and includes the effect of natural gas price risk management activities. The difference between the approved price and the actual cost of the gas purchased is deferred in receivables or payables for future disposition by the OEB.

Property, Plant and Equipment

Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Interest incurred during the construction period is capitalized. Regulated operations capitalize an allowance for interest during construction and, if approved, an allowance for equity funds used during construction, at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment generally is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

Intangibles

Intangibles consist primarily of long-term transportation contracts which are amortized on a straight-line basis over the expected lives of the contracts.

Goodwill

Goodwill is not subject to amortization but is tested for impairment at least annually and written down to fair value if the criteria for impairment are met. Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business.

Asset Retirement Obligations

The fair value of asset retirement obligations associated with the retirement of long-lived assets is recognized in the period when it can be reasonably determined. The fair value, which approximates the cost a third party would charge in performing the tasks necessary to retire such assets, is recognized at the present value of expected future cash flows and is added to the carrying value of the associated asset and depreciated over the asset's useful life. The liability is accreted over time through periodic charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For certain of the Company's assets it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management expects all retirement

costs associated with the regulated pipelines will be recovered through tolls in future periods and therefore any liability recorded would be offset by an asset.

Depreciation expense for Gas Distribution and Services operations includes a provision for asset retirement obligations at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation.

Deferred Amounts and Other Assets

The Company defers certain charges, which the regulatory authorities have permitted or are expected to permit recovery through future rates. Assets are realized and liabilities are settled based on the terms of the regulatory approval once received. The Company recognizes revenues under the terms of a committed long-term delivery contract, which results in a long-term receivable. Other deferred charges are amortized on a straight-line basis over various periods depending on the nature of the charges and include long-term financing and hedging costs, which are amortized over the terms of the related debt or hedged items. The straight-line method of amortization for deferred financing costs approximates the effective interest method.

Derivative Financial Instruments

The Company uses derivative financial instruments and foreign denominated debt to hedge currency risk related to net investments in foreign operations. Gains and losses related to the financial instruments are included in the foreign currency translation adjustment in shareholders' equity. These financial instruments are recognized in the financial statements of the Company at fair value. The net investment hedge strategy is designed such that as foreign cash distributions are received and the net investment decreases, a related portion of the financial instrument is settled and recognized with the distributions. Changes in the value of foreign denominated debt designated as net investment hedges are also included in the foreign currency translation adjustment.

The Company applies settlement accounting to other derivative financial instruments. Under this method, gains and losses on derivative instruments that qualify for hedge accounting are not recorded until they are realized. The notional amounts are not recorded in the financial statements as they do not represent amounts exchanged by the counterparties. Amounts received or paid related to derivative financial instruments used to hedge energy commodities prices are recognized as part of the cost of the underlying physical purchases on settlement. For other derivative financial instruments used to hedge interest costs, amounts received or paid, including any gains and losses realized upon settlement, are recognized over the term of the hedged item.

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

Post-Employment Benefits

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method and are charged to earnings as services are rendered, except for the regulated operations of Gas Distribution and Services, where contributions made to the plan are expensed as paid, consistent with the recovery of such costs in rates. For the defined contribution plans, contributions made by the Company are expensed.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values. Market related values have been calculated using the fair value method. Adjustments arising from plan amendments and the transitional amounts recognized upon adoption of the accounting standard are amortized on a straight-line basis over the average remaining service period of the employees active at the date of amendment or transition. The excess of the net actuarial gain or loss over ten per cent of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees.

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

Services where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2005.

Stock Based Compensation

Stock options granted after January 1, 2003 are accounted for using the fair value method. Under this method, compensation expense is measured at fair value at the grant date using the Black-Scholes option pricing model and recognized on a straight line basis over the vesting period with a corresponding credit to contributed surplus. Stock options granted prior to January 1, 2003 continue to be accounted for as capital transactions when the options are exercised, which does not give rise to compensation expense.

Performance stock units (PSUs) are accounted for over the three-year term of the PSU's whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current performance relative to the specified peer group.

Comparative Amounts

The Company has reclassified the revenues and cost of sales attributable to its marketing business to reflect the gross amounts. Previously, the Company had reported these balances on a net basis. The reclassification reflects changes in the types of transactions undertaken by the business. Prior period comparative amounts have been restated to reflect this change. The change increases Commodity Sales by $1,271.9 million for the year ended December 31, 2004 (2003 — $879.6 million), increases Commodity Costs by $1,267.3 million for the year ended December 31, 2004 (2003 — $873.7 million) and reduces Energy Services revenues by $4.6 million for the year ended December 31, 2004 (2003 — $5.9 million). The reclassification has no impact on operating income, earnings, earnings per share or retained earnings.

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

2. CHANGES IN ACCOUNTING POLICIES

New Accounting Standards

Financial Instruments, Hedging Relationships and Other Comprehensive Income New accounting standards will be in effect for fiscal years beginning on or after October 31, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

Consolidation of Variable Interest Entities

Effective January 1, 2005 the Company adopted, without restatement of prior periods, the accounting guideline for Consolidation of Variable Interest Entities. This new standard requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest as well as a preferred unit investment that has no voting rights, a stated par value and a 30-year maturity. The preferred units earn a return that is equivalent to the cash distributions per unit to the equity unit holders and are classified as a liability in EIF's financial statements. Consolidating EIF, a sponsored investment, had the following impact on the consolidated financial statements

Statement of Financial Position *(millions of dollars)*	**December 31, 2005**
Assets	
Cash and cash equivalents	**11.1**
Accounts receivable and other	**28.9**
Property, plant and equipment, net	**1,218.4**
Deferred amounts and other assets	**40.1**
Intangibles	**103.1**
Goodwill	**308.1**
	1,709.7
Less: Liabilities	
Accounts payable and other	**27.7**
Current portion of non-recourse long-term debt	**27.9**
Non-recourse long-term debt	**1,012.3**
Other long-term liabilities	**7.1**
Future income taxes	**89.2**
Non-controlling interests	**165.5**
	1,329.7
	380.0
Elimination of investment in EIF	**(380.0)**
Net financial position impact	***nil***

Statement of Earnings *(millions of dollars)*	**Year ended December 31, 2005**
Transportation revenue	**249.0**
Less: Expenses	
Operating and administrative	**59.5**
Depreciation and amortization	**71.4**
Other investment income	**8.3**
Interest expense	**61.8**
Income taxes	**0.6**
	201.6
	47.4
Elimination of EIF investment income	**(47.4)**
Net earnings impact	***nil***

Statement of Cash Flows *(millions of dollars)*	**Year ended December 31, 2005**
Operating activities	**62.2**
Investing activities	**(15.1)**
Financing activities	**(50.8)**
Net cash flow impact	**(3.7)**

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

General Information on Rate Regulation and its Economic Effects

A number of businesses within the Company are regulated. The regulators exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers. The Company's regulated businesses with significant accounting impacts on the financial statements are described below:

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are set based on agreements with customers and are filed with the NEB for approval. In 2005, Enbridge and the Canadian Association of Petroleum Producers (CAPP) approved a new incentive tolling settlement (ITS). With the incentive tolling model, Enbridge and shippers share the benefits of cost reductions below agreed levels as well as the benefits of improved quality of service through performance metrics. The new ITS is effective from January 1, 2005 to December 31, 2009 and defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge Mainline System in Canada. In the prior year, tolls were charged in accordance with the previous ITS, in effect from 2000 through 2004. Toll adjustments, for variances from requirements defined in the ITS, are done annually and filed with the regulator for approval.

Athabasca Pipeline

The Athabasca Pipeline is regulated by the AEUB. Tolls are established based on long-term transportation agreements with individual shippers.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline regulated by the FERC under the terms of the Natural Gas Act and the Natural Gas Policies Act. Vector operates under a FERC approved tariff that establishes rates, terms and conditions under which it provides services to its customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC, through two methods. First, the Company may voluntarily seek a tariff change by making a tariff filing, which justifies proposed changes and provides notice, generally 30 days, to the appropriate parties. Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding. Tolls include a return on equity component of 12.96% before tax.

Alliance Pipeline

The US portion of the Alliance Pipeline (Alliance) is regulated by the FERC whereas the Canadian portion of the pipeline is regulated by the NEB. Shippers on Alliance entered into 15-year transportation contracts, expiring in December 2015, with a cost-of-service toll methodology. Alliance estimates the tolls necessary to recover the projected costs of providing transportation service to its shippers in accordance with its transportation contracts and regulations. Toll adjustments are made annually with tolls being submitted to shippers and filed with the regulator. The tolls include a return on equity component of 10.85% after tax for the US portion and 11.25% after tax for the Canadian portion. Alliance tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution Inc.

The gas distribution operations of EGD are regulated by the OEB. EGD's rates for 2005 are set under a cost of service methodology that allows revenues to be set to recover EGD's forecast costs and to earn a rate of return on common equity. Applications for changes to rates are made annually and are submitted by EGD for approval by the OEB.

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in gas distribution, storage and transmission and an allowance for working capital. Under cost of service, it is the responsibility of EGD to demonstrate to the OEB the prudence of the costs it has incurred. For 2005, EGD's

approved rate of return on the rate base was 8.10% after tax, and the approved rate of return on common equity was 9.57% after tax based on a 35% deemed common equity for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the New Brunswick Board of Commissioners of Public Utilities Board (PUB) and follows a cost of service tolling methodology. An application for rate adjustments is filed annually with the PUB for their approval. For 2005, EGNB's approved rate of return on the rate base was 9.46% before tax and the approved rate of return on equity was 13% before tax based on equity for regulatory purposes which is capped at 50%.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The regulatory assets and liabilities recorded in the financial statements are based upon an expectation of the future actions of the regulator. To the extent that the regulator's future actions are different from the Company's expectations, the timing and amount of recovery or settlement of amounts recorded on the statement of financial position could be significantly different from the timing and amounts that are eventually recovered or settled.

Financial Statement Effects

In order to recognize the economic effects of the actions or expected actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulated accounting, GAAP would not permit deferral of regulatory assets and therefore the earnings impact would be recorded in the period of recovery. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets in the consolidated statement of financial position whereas current regulatory assets are recorded in Accounts Receivable.

Regulatory liabilities represent amounts that are expected to be refunded to customers as a result of the rate-setting process. The GAAP treatment of regulatory liabilities and the resulting earnings impact is the same as that under rate regulated accounting because the liabilities represent contractual obligations. Regulatory liabilities are recorded in Accounts Payable.

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

(millions of dollars) **December 31,**	**2005**	2004	Settlement Period (years)	Earnings Impact[1]
Regulatory Assets and (Liabilities)				
Liquids Pipelines				
Tolling deferrals[2]	**172.3**	151.0	1	**21.3**
Gas Pipelines				
Deferred transportation revenue[3]	**187.6**	170.3	18 - 20	**14.6**
Transportation revenue adjustment[4]	**11.7**	12.6	1	**(0.3)**
Sponsored Investments				
Deferred transportation revenue[3]	**30.0**	—	20	**0.1**
Gas Distribution and Services				
Regulatory deferral[5]	**82.7**	61.0	35	**14.4**
Deferred taxes recoverable[6]	**14.0**	23.9	2	**—**
Ontario hearing cost[7]	**11.9**	8.0	2	**2.5**
Purchased gas variance[8]	**28.1**	(47.6)	1	**49.2**
Unaccounted for gas variance[9]	**3.0**	(32.7)	1	**23.2**
Deferred rebates[10]	**(11.6)**	(10.7)	1	**(0.6)**
Earnings sharing deferral[11]	**—**	(13.4)	1	**—**
Transactional services deferral[12]	**(13.1)**	(1.2)	1	**(7.7)**

1. Represents the effect, increase/(decrease), on 2005 after tax earnings as a result of the treatment under rate regulated accounting.

2. Tolls on the Enbridge System are calculated in accordance with the ITS, System Expansion Program (SEP) II and the Terrace agreement which stipulate that tolls are to be established each year based on capacity as per the ITS, the allowed revenue requirement and the Terrace surcharge. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a receivable is recognized and incorporated into tolls in the subsequent year. However, recovery is dependent on volumes shipped since each shipper is only responsible for their pro-rata share of the increase in tolls. In addition, other tolling deferrals arise as determined in accordance with the various agreements.

3. Deferred transportation revenue is related to the cumulative difference between depreciation expense included in the financial statements of Alliance and Vector Pipelines and depreciation expense included in regulated transportation rates. The companies expect to recover this difference over a number of years, beginning in 2011 and ending in 2025 for Alliance and beginning in 2008 and ending in 2023 for Vector, when depreciation rates as prescribed in the transportation agreements are expected to exceed the depreciation rates applied in the financial statements. This regulatory asset is not included in the rate base upon which the return on equity is calculated.

4. The transportation revenue adjustment is related to the cumulative difference between actual expenses included in the financial statements of Alliance and estimated expenses included in transportation rates. Differences between actual and estimated costs are recoverable under negotiated long-term transportation agreements with shippers. The transportation revenue adjustment is not included in the rate base upon which the return on equity is calculated.

5. The PUB has approved a regulatory deferral account to capture the difference between EGNB's distribution revenues and its cost of service during the development period. The regulatory deferral account balance is to

be amortized over a recovery period as approved by the PUB commencing at the end of the development period, currently expected in 2010. In a decision rendered in January 2005, the PUB has indicated that the recovery period would end no sooner than December 31, 2040.

6. Deferred taxes recoverable relate to the former rental water heater program of EGD. On November 1, 2004, the OEB authorized EGD to collect from ratepayers $23.9 million, after tax, over a three-year period beginning October 1, 2004. No earnings impact resulted during 2005 since all collections from the rate payers in the period were applied towards recovery of the receivable.

7. Ontario hearing costs represent the amount incurred by EGD on the rate hearing process. EGD has historically been granted approval, by the OEB, for recovery of such hearing costs within one or two years.

8. Purchased gas variance represents the difference between the actual and estimated cost of gas purchased by EGD, including risk management costs. The estimated cost of gas is approved by the OEB and is built into rates. EGD has historically been granted approval for recovery or refund of this variance within a year.

9. Unaccounted for gas variance represents the difference between the total gas distributed by EGD and the amount of gas billed or billable to customers for their recorded consumption, to the extent it is different from the estimated amount built into rates. Based on approval from the OEB, EGD has deferred unaccounted for gas and has been granted approval for recovery or refund of this amount in the subsequent year.

10. Deferred rebates represent an accumulation of amounts that were required by the OEB to be refunded to ratepayers of EGD but remain pending due to the inability to locate certain customers. This amount would be refunded to ratepayers in the following year.

11. Earnings sharing deferral represents the ratepayer's portion of EGD's earnings in excess of the allowed return on equity for 2004 which is required to be refunded to ratepayers as stipulated by the OEB. The 2004 amount of $13.4 million was refunded to ratepayers during 2005.

12. Transactional services deferral represents the ratepayer portion of excess earnings generated from optimization of storage and pipeline capacity. EGD has historically been required by the OEB to refund the amount to ratepayers in the following year.

Other Items Affected by Rate Regulation

Future Income Taxes

The regulated activities of the Company recover tax expense based on the taxes payable method when prescribed by regulators for ratemaking purposes or when stipulated in ratemaking agreements. Therefore, rates do not include the recovery of future income taxes related to temporary differences. Consequently, the Company does not record future income taxes for these regulated activities as the Company expects that all future income taxes will be recovered in rates when they become payable. GAAP requires the recognition of future income tax liabilities and future income tax assets in the absence of rate regulation.

Net future income tax liabilities recorded of $77.8 million (2004 — $35.9 million) arise from temporary differences related to certain regulatory deferral accounts identified above. Accumulated unrecorded future income taxes of $71.9 million (2004 — $54.1 million) relate to the remaining regulatory deferral accounts identified above. In the absence of rate regulated accounting, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. However, future income taxes associated with certain assets, primarily property, plant and equipment, would be recorded, in the absence of rate regulated accounting, resulting in the recognition of $654.1 million (2004 — $552.6 million) in future income tax liabilities. As a result of these impacts, earnings would decrease by $10.0 million in the year ended December 31, 2005.

Allowance For Funds Used During Construction (AFUDC) and Other Capitalized Costs

AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC for rate-regulated entities includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, GAAP would permit the capitalization of only the interest component. Therefore, the set up of the equity component as a capitalized asset and the corresponding earnings recognized during the construction phase would not be recognized nor would the subsequent depreciation of the capitalized equity component. It is not possible to make a reasonable estimate of

the carrying value of the equity component of AFUDC under the pool method of depreciation, prescribed by certain regulators. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as a pool of assets.

Under the pool method of accounting, when a fixed asset is retired or otherwise disposed of, no gain or loss is reflected in income. Entities not subject to rate regulation write off the net book value of the retired asset, and include any resulting gain or loss in current operating results. Since the Company does not calculate depreciation expense for individual assets, it cannot identify or quantify gains or losses on the retirement of fixed assets in any given year. Similarly, it cannot state the effect on depreciation expense of using the pool method.

Operating Cost Capitalization

With the approval of the regulator, EGD, capitalizes a percentage of certain operating costs into the rate base on an on-going basis. Such treatment is accorded in recognition of the unique business circumstances faced by rate-regulated entities. EGD is authorized to charge depreciation and earn a rate of return on the net book value of such capitalized costs in future years. In the absence of rate regulated accounting, such overhead costs would need to be charged to the consolidated statement of earnings in the period in which they occurred.

EGD entered into a consulting contract relating to services provided in respect of work and asset management initiatives. The majority of the related costs, primarily consulting fees, are being capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2005, $48.1 million (2004 $18.3 million) was included in gas mains, which are depreciated over the average service life of 25 years. In the absence of rate regulated accounting, the majority of these costs would need to be charged to the consolidated statement of earnings in the period in which they occurred.

Pension Plans

The Company maintains a pension plan which provides defined benefit pension benefits. For the regulated operations of Gas Distribution and Services, contributions made to the plan are expensed as paid, consistent with the recovery of such costs in rates. Under GAAP, pension costs and obligations for defined benefit pension plans are determined using the projected benefit method and are charged to earnings as services are rendered. Had pension costs and obligations been recognized, the net pension asset would have increased by $191.8 million (2004 — $163.0 million) at December 31, 2005 and earnings would have decreased by $0.9 million after tax for the year ended December 31, 2005.

Post-Employment Benefits Other than Pensions

The Company also provides for post-employment benefits other than pensions (OPEB). For the regulated operations of Gas Distribution and Services, the cost of providing these benefits are expensed when paid, consistent with the recovery of such costs in rates. Under GAAP, the cost of such benefits is accrued during the years employees render service. Had these costs been accrued, the net OPEB liability would have increased by $60.2 million (2004 — $54.8 million) at December 31, 2005 and earnings would have decreased by $4.0 million after tax for the year ended December 31, 2005.

4. SEGMENTED INFORMATION

Year ended December 31, 2005

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	**881.0**	**364.3**	**249.0**	**6,947.1**	**11.7**	**—**	**8,453.1**
Commodity costs	**—**	**—**	**—**	**(5,728.4)**	**—**	**—**	**(5,728.4)**
Operating and administrative	**(311.4)**	**(95.5)**	**(60.1)**	**(549.3)**	**(17.5)**	**(23.8)**	**(1,057.6)**
Depreciation and amortization	**(145.6)**	**(94.3)**	**(71.5)**	**(257.3)**	**(1.2)**	**(5.4)**	**(575.3)**
	424.0	**174.5**	**117.4**	**412.1**	**(7.0)**	**(29.2)**	**1,091.8**
Investment and other income	**(0.9)**	**5.9**	**54.7**	**35.7**	**97.7**	**38.5**	**231.6**
Interest and preferred share dividends	**(96.5)**	**(81.9)**	**(61.8)**	**(178.8)**	**—**	**(127.1)**	**(546.1)**
Income taxes	**(97.5)**	**(38.7)**	**(45.5)**	**(90.2)**	**(3.3)**	**53.9**	**(221.3)**
Earnings applicable to common shareholders	**229.1**	**59.8**	**64.8**	**178.8**	**87.4**	**(63.9)**	**556.0**

Year ended December 31, 2004

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services[2]	International	Corporate[1]	Consolidated
Revenues	872.7	271.7	—	6,631.1	32.3	—	7,807.8
Commodity costs	—	—	—	(5,184.3)	—	—	(5,184.3)
Operating and administrative	(310.1)	(55.1)	—	(577.0)	(38.6)	(34.2)	(1,015.0)
Depreciation and amortization[3]	(145.4)	(65.7)	—	(308.4)	(1.9)	(3.6)	(525.0)
	417.2	150.9	—	561.4	(8.2)	(37.8)	1,083.5
Investment and other income	1.8	0.8	112.2	50.6	81.5	14.8	261.7
Gain on sale of investment	—	—	—	121.5	—	—	121.5
Interest and preferred share dividends	(101.4)	(65.6)	—	(211.1)	(0.2)	(153.9)	(532.2)
Income taxes	(97.7)	(32.3)	(46.0)	(209.3)	0.5	95.6	(289.2)
Earnings applicable to common shareholders	219.9	53.8	66.2	313.1	73.6	(81.3)	645.3

Year ended December 31, 2003

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services[5]	International	Corporate[1]	Consolidated
Revenues	821.5	222.1	—	4,659.1	26.2	0.1	5,729.0
Commodity costs	—	—	—	(3,593.8)	—	—	(3,593.8)
Operating and administrative	(288.8)	(41.2)	—	(415.9)	(30.5)	(24.4)	(800.8)
Depreciation and amortization	(142.6)	(56.7)	—	(237.6)	(2.0)	(4.1)	(443.0)
	390.1	124.2	—	411.8	(6.3)	(28.4)	891.4
Investment and other income	3.4	36.6	113.1	19.8	78.1	(42.8)	208.2
Gain on sale of assets	—	—	239.9	—	—	—	239.9
Interest and preferred share dividends	(102.1)	(58.7)	—	(162.2)	(0.5)	(176.2)	(499.7)
Income taxes	(77.9)	(32.0)	(118.7)	(115.8)	1.0	170.8	(172.6)
Earnings applicable to common shareholders	213.5	70.1	234.3	153.6	72.3	(76.6)	667.2

1. *Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments.*

2. *Gas Distribution and Services includes 15 months of results for EGD and other gas distribution businesses, for the year end December 31, 2004. This change eliminated the quarter lag basis of consolidation and resulted in additional earnings of $57.2 million.*

3. *Depreciation expense in Gas Distribution and Services includes a $12.4 million impairment loss on the Calmar Gas Plant.*

4. *The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 1.*

5. *The 2003 results for Gas Distribution and Services for the year end 2003 are on a quarter lag basis, and therefore include the 12 months ended September 30, 2003.*

Total Assets

(millions of dollars)

December 31,	**2005**	2004
Liquids Pipelines	**3,594.2**	3,410.7
Gas Pipelines	**2,321.8**	2,310.2
Sponsored Investments	**2,451.9**	1,116.3
Gas Distribution and Services	**7,318.5**	6,599.4
International	**894.9**	958.6
Corporate	**629.6**	509.9
	17,210.9	14,905.1

Additions to Property, Plant and Equipment

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Liquids Pipelines	**225.4**	83.3	123.4
Gas Pipelines	**10.1**	10.6	11.3
Sponsored Investments	**15.5**	—	—
Gas Distribution and Services	**427.2**	402.1	249.0
International and Corporate	**2.4**	0.4	7.6
	680.6	496.4	391.3

Geographic Information

Revenues[1]

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Canada	**6,747.5**	6,297.6	4,613.1
United States	**1,693.9**	1,482.6	1,089.6
Other	**11.7**	27.6	26.3
	8,453.1	7,807.8	5,729.0

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

Property, Plant and Equipment

(millions of dollars)

December 31,	**2005**	2004
Canada	**8,246.5**	6,819.2
United States	**2,216.0**	2,241.8
Other	**4.1**	5.5
	10,466.6	9,066.5

5. DISPOSITIONS

AltaGas Income Trust (AltaGas)

During 2004, the Company disposed of its investment in AltaGas for cash proceeds of $346.7 million net of underwriting fees, resulting in an after-tax gain of $97.8 million ($121.5 million pre-tax).

Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) Inc.

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, the Company sold its 50% interest in the Canadian segment of the Alliance Pipeline together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. to EIF for total proceeds of $905.0 million before working capital adjustments of $20.6 million and transaction costs of $0.2 million. The Company recorded an after-tax gain on the sale of $169.1 million ($239.9 million pre-tax).

6. ACQUISITIONS

Enbridge Offshore System

On December 31, 2004, the Company acquired offshore natural gas pipeline assets located in the Gulf of Mexico, from Shell US Gas & Power LLC for cash consideration of $754.0 million. The assets are held primarily through joint ventures with ownership interests ranging from 22% to 80%. This acquisition expands the Company's natural gas pipeline operations. The acquisition has been accounted for using the purchase method with the results of operations included in the consolidated financial statements from December 31, 2004. The value allocated to the assets was determined by an independent appraisal.

Spearhead Pipelines

In September 2003, the Company acquired 90% of the outstanding shares of CCPS Transportation L.L.C., owner of the Spearhead Pipelines (formerly known as the Cushing to Chicago Pipeline System) for $145.8 million. In 2005, the Company acquired the final 10% for $15.4 million (US $12.4 million).

The acquisitions were accounted for using the purchase method and the results of operations have been included in the consolidated statement of earnings from the dates of acquisition. The amounts paid were allocated to property, plant and equipment.

Other

In 2005, the Company acquired interests in other businesses for a total of $91.2 million (2004 - $17.5 million), including $6.8 million paid in common shares of the Company.

(millions of dollars)	**Combined 2005**	Offshore 2004
Fair Value of Assets Acquired:		
Property, plant and equipment	**66.6**	591.8
Intangibles	**25.7**	133.9
Goodwill	**30.8**	31.5
Other assets	**0.7**	22.5
Future income taxes	**(16.3)**	—
Other liabilities	**(0.9)**	(25.7)
	106.6	754.0
Purchase Price:		
Cash (2004, includes cash acquired of $9.5 million)	**88.6**	752.9
Contingent consideration	**11.2**	—
Shares issued	**6.8**	—
Transaction costs	—	1.1
	106.6	754.0

Factors that contributed to goodwill include the retention of key employees, existing customer base, and the potential to use the assets to accommodate the transportation needs of several proposed liquified natural gas (LNG) regasification projects.

7. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)

December 31, 2005	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.4%	2,468.3	1,173.5	1,294.8
Pumping Equipment, Buildings, Tanks and Other	3.8%	2,263.9	801.3	1,462.6
Land and Right-of-Way	1.9%	36.9	17.9	19.0
Under Construction	—	297.3	2.1	295.2
		5,066.4	1,994.8	3,071.6
Gas Pipelines				
Pipeline	4.0%	1,930.9	309.4	1,621.5
Land and Right-of-Way	2.8%	45.1	6.3	38.8
Metering and Other	5.5%	125.5	13.9	111.6
Under Construction	—	22.0	—	22.0
		2,123.5	329.6	1,793.9
Sponsored Investments				
Pipeline	3.2%	1,340.2	142.9	1,197.3
Other	9.5%	28.4	7.3	21.1
		1,368.6	150.2	1,218.4
Gas Distribution and Services				
Gas Mains	4.1%	2,146.9	462.7	1,684.2
Gas Services	4.5%	1,883.8	473.2	1,410.6
Regulating and Metering Equipment	3.8%	600.8	135.9	464.9
Storage	2.7%	267.7	54.4	213.3
Computer Technology	17.2%	333.9	168.7	165.2
Other	3.8%	516.2	103.0	413.2
		5,749.3	1,397.9	4,351.4
Other	8.8%	58.3	27.0	31.3
		14,366.1	3,899.5	10,466.6

(millions of dollars)

December 31, 2004	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.4%	2,534.4	1,118.8	1,415.6
Pumping Equipment, Buildings, Tanks and Other	3.8%	2,255.9	730.4	1,525.5
Land and Right-of-Way	2.1%	38.1	17.5	20.6
Under Construction	—	37.4	—	37.4
		4,865.8	1,866.7	2,999.1
Gas Pipelines				
Pipeline	3.8%	1,915.7	239.5	1,676.2
Land and Right-of-Way	3.0%	51.4	5.4	46.0
Metering and Other	5.2%	122.8	13.8	109.0
Under Construction	—	35.8	—	35.8
		2,125.7	258.7	1,867.0
Gas Distribution and Services				
Gas Mains	4.0%	1,920.5	377.0	1,543.5
Gas Services	4.5%	1,759.9	426.4	1,333.5
Regulating and Metering Equipment	3.7%	556.6	118.0	438.6
Storage	2.7%	254.7	44.8	209.9
Computer Technology	16.1%	308.5	164.4	144.1
Other	4.7%	574.8	79.1	495.7
		5,375.0	1,209.7	4,165.3
Other	10.7%	61.2	26.1	35.1
		12,427.7	3,361.2	9,066.5

8. JOINT VENTURES

Enbridge has joint venture interests in the following entities:

(millions of dollars)

December 31,	Ownership Interest	Net Assets 2005	2004
Liquids Pipelines			
Mustang Pipeline	30.0%	**21.7**	18.8
Hardisty Caverns	50.0%	**34.7**	35.5
Gas Pipelines			
Alliance Pipeline US	50.0%	**415.5**	423.0
Vector Pipeline	60.0%	**448.4**	472.6
Enbridge Offshore Pipelines — various joint ventures	22.0% - 75.0%	**503.0**	651.5
Sponsored Investment			
Alliance Pipeline Canada	50.0%	**368.3**	—
Gas Distribution & Services			
Aux Sable	42.7%	**180.7**	204.7
CustomerWorks Limited Partnership	70.0%	**68.0**	59.9
Other	33.0% - 50.0%	**34.6**	26.2
		2,074.9	1,892.2

Following is a summary of the impact of the joint ventures on the consolidated financial statements of Enbridge:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Earnings			
Revenues	**1,402.5**	989.7	546.8
Commodity costs	**(608.2)**	(482.4)	(168.1)
Operating and administrative	**(320.7)**	(241.3)	(182.1)
Depreciation and amortization	**(162.3)**	(81.5)	(59.8)
Interest expense	**(117.1)**	(66.6)	(60.4)
Investment and other income	**4.6**	2.2	6.7
Proportionate share of net earnings	**198.8**	120.1	83.1
Cash Flows			
Cash provided by operations	**271.1**	158.7	128.6
Cash (used in)/provided by investing activities	**(13.4)**	(32.0)	0.7
Cash used in financing activities	**(268.0)**	(126.0)	(218.1)
Proportionate share of increase/(decrease) in cash and cash equivalents	**(10.3)**	0.7	(88.8)

(millions of dollars)

December 31,	**2005**	2004
Financial Position		
Current assets	**273.7**	202.0
Property, plant and equipment, net	**3,168.2**	2,162.8
Deferred amounts and other assets	**245.6**	353.5
Current liabilities	**(231.8)**	(120.2)
Long-term debt	**(1,366.0)**	(701.4)
Other long-term liabilities	**(14.8)**	(4.5)
Proportionate share of net assets	**2,074.9**	1,892.2

Included in the Company's proportionate share of cash from joint ventures is $16.4 million (2004 — $6.0 million) held in trust, pursuant to finance agreements held by joint ventures.

9. LONG-TERM INVESTMENTS

(millions of dollars)

December 31,	Ownership Interest	2005	2004
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	22.8%	**21.7**	23.0
Sponsored Investments			
The Partnership	10.9%	**738.1**	730.1
Enbridge Income Fund	41.9%	**—**	0.1
Gas Distribution and Services			
Noverco	32.1%	**28.7**	46.0
Other		**1.3**	3.0
International			
Compañía Logistica de Hidrocarburos (CLH)	25.0%	**596.1**	663.6
Corporate		**2.2**	2.6
Cost Investments			
Liquids			
Value Creation		**25.0**	—
Sponsored Investments			
Enbridge Income Fund		**—**	380.2
Gas Distribution and Services			
Noverco		**181.4**	181.4
Fuel Cell Energy		**25.0**	25.0
International			
OCENSA Pipeline		**223.3**	223.3
		1,842.8	**2,278.3**

Equity investments include $560.1 million (2004 — $543.1 million) representing the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the date of purchase. The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values and is amortized over the economic life of the assets.

The Partnership

The Company has a combined 10.9% ownership in EEP, through a 2.0% interest in general partner units, a 5.9% direct interest in Class B partnership units, and a 17.2% interest in EEM, which owns 17.5% of EEP through an investment in i-units of EEP for an effective ownership interest of 3.0%.

Although 82.8% of EEM is widely held, the Company has voting control and, therefore, consolidates EEM's investment in EEP of $491.6 million (2004 — $480.6 million). The Class B partnership units and the general partner units are recorded at $246.5 million (2004 — $249.5 million).

In both 2004 and 2005, EEP completed public issuances of partnership units. As the Company elected not to fully participate in these offerings, its effective interest in EEP was reduced to 10.9% from 11.6% (2004 — 11.6% from 12.2%). This resulted in recognition of a dilution gain of $8.9 million (2004 — $7.6 million), net of tax and minority interest.

Enbridge Income Fund

The Company owns 14,500,000 subordinated units of EIF and 38,023,750 preferred units of Enbridge Commercial Trust (ECT), a subsidiary of EIF, at December 31, 2005. The Company commenced consolidation of EIF on January 1, 2005 in accordance with the new accounting guideline on Consolidation of Variable Interest Entities. Prior to January 1, 2005, EIF was accounted for as an equity investment and the ECT preferred units were accounted for as a cost investment. The market value of the subordinated units of EIF at December 31, 2005 is $210.0 million (2004 — $202.1 million).

At the request of the Company, the ECT preferred units will be repurchased for cancellation in certain specified circumstances by ECT with a repurchase price per ECT preferred unit based on the net issue price realized from the sale (or that could be realized from the sale) of an ordinary trust unit to the public. The ECT preferred units have no voting rights and mature on June 30, 2033 at which time ECT is obligated to redeem all of the outstanding ECT preferred units for a price of ten dollars per unit. The economic terms of these units are similar to those of ordinary common units. As such, the approximate fair value of these preferred units, valued at the December 31, 2005 closing price of $14.48 per ordinary trust unit (2004 — $13.94), is $550.6 million (2004 — $530.1 million).

Noverco

The Company owns a cost investment in Noverco of $181.4 million (2004 — $181.4 million), which is entitled to a cumulative dividend based on the average yield of Government of Canada bonds maturing in more than 10 years plus 4.34%. The fair value of the investment approximates its carrying value as its return is based on a floating rate.

The Company also owns an equity investment in the common shares of Noverco of $28.7 million (2004 — $46.0 million). Noverco holds an approximate 10% reciprocal shareholding in the Company. As a result, the Company has a pro-rata interest of 3.2% (2004 — 3.2%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $135.7 million (2004 — $135.7 million). Dividends paid by the Company to Noverco are eliminated from the equity earnings of Noverco.

During the year the Company reclassified $51.2 million in dividends paid to Noverco. The reclassification increased equity investments and retained earnings by $51.2 million and represents the reciprocal portion of dividends paid to Noverco from September 1, 1997 to December 31, 2004. The reciprocal shareholding results in a portion of the dividends paid to Noverco effectively reducing the amount of dividends paid by the Company and reflects an additional investment in Noverco.

CLH

The Company owns a 25% equity interest in CLH, a refined products transportation and storage company in Spain.

Subsequent to the initial purchase of $430.8 million, contingent payments of 46.4 million Euros ($73.2 million) have been made to the vendors pursuant to annual and cumulative volume targets being met, as stipulated in the initial purchase and sale agreement. The final contingent payment of 38.4 million Euros ($53.0 million) has been accrued at December 31, 2005.

OCENSA Pipeline

The Company owns a cost investment in the OCENSA Pipeline of $223.3 million (2004 — $223.3 million), which earns a fixed rate of return. The fair value of this investment is approximately $257.9 million (2004 — $254.3 million), estimated using year-end market information.

Income from Equity Investments

(millions of dollars)

Year ended December 31,	2005	2004	2003
Liquids Pipelines	**0.8**	1.1	1.1
Gas Pipelines	**—**	—	31.6
Sponsored Investments	**48.6**	79.5	73.3
Gas Distribution and Services	**8.9**	29.4	19.9
International	**58.5**	49.6	45.7
Corporate	**—**	0.7	1.2
	116.8	160.3	172.8

Consolidated retained earnings at December 31, 2005 include undistributed earnings from equity investments of $12.3 million (2004 — $121.8 million).

10. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars)

December 31,	2005	2004
Regulatory deferrals	**336.3**	266.8
Contractual receivables	**132.5**	118.6
Long-term portion of hedge fair value changes	**221.1**	179.9
Deferred pension funding	**61.7**	65.0
Deferred financing charges	**42.8**	39.5
Other	**99.8**	59.4
	894.2	729.2

At December 31, 2005, deferred amounts of $129.8 million (2004 — $114.7 million) were subject to amortization. Amortization expense related to deferred amounts in 2005 was $12.5 million (2004 — $13.9 million; 2003 — $18.4 million). Accumulated amortization at the December 31, 2005 is $62.1 million (2004 — $55.6 million).

11. INTANGIBLE ASSETS

(millions of dollars)

December 31, 2005	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Gas Pipelines				
Long-term transportation agreements	**4.0%**	**129.7**	**5.2**	**124.5**
Sponsored Investments				
Long-term transportation agreements	**4.4%**	**116.0**	**12.9**	**103.1**
Gas Distribution and Services				
Long-term transportation agreements	**4.8%**	**15.9**	**—**	**15.9**
Customer lists	**7.1%**	**9.8**	**0.7**	**9.1**
		271.4	**18.8**	**252.6**

(millions of dollars)

December 31, 2004		Cost	Accumulated Depreciation	Net
Gas Pipelines				
Long-term transportation agreements	4.0%	133.9	—	133.9

Increases to intangible assets in the period include $116.0 million in long-term transportation agreements of Alliance Pipeline Canada, a subsidiary of EIF which is consolidated with Enbridge effective January 1, 2005, $15.9 million in long-term transportation agreements of Leader Wind Corp., acquired on November 21, 2005 and $9.8 million (US$8.4 million) in customer lists of U.S. Oil, acquired on January 6, 2005.

During 2005, amortization expense relating to intangible assets is $11.1 million (2004 — nil, 2003 — nil). Amortization of the Leader Wind Corp. transportation agreements will commence at the in service date, anticipated in 2007.

12. GOODWILL

(millions of dollars)

	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	Consolidated
Balance at January 1, 2004	—	—	—	—
Acquired in conjunction with Enbridge Offshore Pipelines	31.5	—	—	31.5
Balance at December 31, 2004	31.5	—	—	31.5
Acquired in conjunction with U.S. Oil	—	—	20.1	20.1
Acquired in conjunction with Leader Wind Corp.	—	—	9.9	9.9
Included in EIF consolidation (note 2)	—	308.1	—	308.1
Effects of foreign exchange	(1.6)	—	(0.8)	(2.4)
Balance at December 31, 2005	**29.9**	**308.1**	**29.2**	**367.2**

13. DEBT

(millions of dollars)

December 31,	Weighted Average Interest Rate	Maturity	2005	2004
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	200.0
Medium-term notes	5.73%	2009-2029	**673.0**	622.8
Other[1]			**166.4**	90.6
Gas Distribution and Services				
Debentures	10.98%	2009-2024	**585.0**	585.0
Medium-term notes	6.04%	2008-2033	**1,190.0**	1,230.0
Other			**11.7**	8.4
Corporate				
US Dollar term notes (US$417 million, 2004 — US$275 million)	5.82%	2007-2015	**486.2**	331.0
Medium-term notes	5.87%	2006-2035	**1,988.4**	1,692.5
Preferred securities	7.80%	2051	**200.0**	200.0
Other[2]			**1,179.6**	1,796.9
Total Debt			**6,680.3**	6,757.2
Current maturities of long-term debt			**401.2**	530.2
Other short-term debt			**—**	173.7
Current Maturities and Short-Term Debt			**401.2**	703.9
Long-Term Debt			**6,279.1**	6,053.3

1. Primarily commercial paper borrowings.

2. Primarily commercial borrowings. Includes US$256.9 million (2004 — US$585.0 million).

Short-term debt of $1,340.5 million (2004 — $1,361.1 million) is supported by the availability of long-term committed credit facilities and has been classified as long-term debt.

Long-term debt maturities for the years ending December 31, 2006 through 2010 are $401.2 million, $337.1 million, $452.7 million, $350.9 million and $601.1 million, respectively.

The Company has $200.0 million of 7.8% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after February 15, 2007, being the fifth anniversary of their issue. The Company has the right to defer, subject to certain conditions, payments of distributions on the securities for up to 20 consecutive quarterly periods. Deferred and regular distribution amounts are payable in cash or, at the option of the Company, in common shares of the Company.

Interest Expense

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Long-term debt	**382.8**	442.8	409.4
Non recourse long-term debt	**112.1**	54.5	58.7
Commercial paper and other short-term debt	**40.6**	21.7	20.2
Short-term borrowings	**12.7**	10.5	9.6
Capitalized	**(9.0)**	(4.2)	(5.1)
	539.2	525.3	492.8

In 2005, total interest paid was $537.1 million (2004 — $549.3 million; 2003 — $508.6 million).

Credit Facilities

(millions of dollars)

December 31, 2005	Expiry Dates	Available	Drawdowns
Liquids Pipelines	2006	150.0	—
Gas Distribution and Services	2006	1,105.8	303.5
Corporate	2006 - 2010	2,199.0	—
		3,454.8	303.5

Credit facilities carry a weighted average standby fee of 0.095% per annum on the unutilized portion and drawdowns bear interest at prevailing market rates. The credit facilities serve as a backstop to the commercial paper programs and the Company has the option, at its sole discretion, to extend the facilities from 2006 to 2007 should lenders fail to renew their credit commitments.

14. NON-RECOURSE DEBT

(millions of dollars)

December 31,	2005	2004
Gas Pipelines		
Credit Facilities of Alliance Pipeline US (US$7.7 million, 2004 — US$8.9 million)	**8.9**	10.6
Senior Notes of Alliance Pipeline US		
7.770% due 2015 (US$128.8 million, 2004 — US$134.7 million)	**150.1**	162.1
6.996% due 2019 (US$131.8 million, 2004 — US$143.2 million)	**153.7**	172.3
7.877% due 2025 (US$100.0 million, 2004 — US$100.0 million)	**116.6**	120.4
4.591% due 2025 (US$134.5 million, 2004 — US$140.6 million)	**156.8**	169.3
Capital leases obligations	**—**	0.8
	586.1	635.5
Gas Distribution and Services		
Term debt of Aux Sable (US$4.2 million)	**4.9**	—
Capital leases obligations	**56.9**	59.9
	61.8	59.9
Sponsored Investments		
Credit Facility of Enbridge Income Fund	**11.0**	—
Credit Facility of Alliance Pipeline Canada	**24.1**	—
Medium Term Notes of Enbridge Income Fund		
4.19% due 2009	**100.0**	—
5.25% due 2014	**90.0**	—
Senior Notes of Alliance Pipeline Canada		
7.230% due 2015	**126.5**	—
7.181% due 2023	**186.7**	—
7.217% due 2025	**149.2**	—
6.765% due 2025	**178.8**	—
5.546% due 2023	**120.4**	
Fair value increment on long-term debt acquired	**53.5**	
	1,040.2	—
Current Maturities	**(68.2)**	(30.2)
	1,619.9	665.2

Long-term debt maturities on non-recourse borrowings for the years ending December 31, 2006 through 2010 are $68.2 million, $60.4 million, $99.7 million, $171.9 million and $78.2 million, respectively.

Alliance Pipeline US

Interest and principal repayments on the Senior Notes are payable semi-annually each June 30 and December 31; principal repayments on the 7.877% Senior Notes commence June 2019. Principal repayments are closely tied to the recovery rates for capital depreciation and income taxes contained in the transportation agreements.

Aux Sable

The term debt of Aux Sable is for capital funding, bears interest at Libor plus 2%, and is repayable 20% on the third and fourth anniversaries, 2008 and 2009, respectively, and 60% on the fifth anniversary, 2010.

Enbridge Income Fund

The Medium Term Notes (MTNs) are redeemable by EIF prior to maturity, in whole or in part, at the option of EIF by giving at least 30 days, and not more than 60 days, notice to the holders, at the Government of Canada yield plus 0.14% and 0.25% for the Series 1 and Series 2 MTNs, respectively. Interest on the MTNs is payable semi-annually in June and December.

The Senior Notes may be redeemed by Alliance Pipeline Canada at any time at a price equal to the greater of (i) the applicable Government of Canada yield price plus a premium and (ii) par, together with accrued interest.

Alliance Pipeline Canada may be required to redeem the Senior Notes, in whole or in part, from proceeds received under insurance claims or other claims for damages if the proceeds are not applied to repair or rebuild the Alliance pipeline system.

Interest on the Senior Notes is payable semi-annually in June and December. Principal repayments are closely tied to the recovery rates for depreciation contained in the transportation agreements.

15. NON-CONTROLLING INTERESTS

(millions of dollars)

December 31,	**2005**	2004
EEM	**370.1**	369.8
EGD preferred shares	**100.0**	100.0
EIF	**165.5**	—
Other	**55.4**	45.1
	691.0	514.9

Non-controlling interest in EEM represents 82.8% of the listed shares of EEM.

The 4,000,000 4.82% Cumulative Redeemable EGD Preferred Shares are entitled to fixed, cumulative, preferential dividends which gives them a priority claim on the assets of EGD prior to the common shareholder, Enbridge. Subsequent to July 1, 2009, EGD may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 plus all accrued and unpaid dividends to the redemption date.

Non-controlling interest in EIF represents 58.1% of EIF held by ordinary unitholders.

16. SHARE CAPITAL

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

Common Shares

(millions of dollars; number of common shares in millions)

December 31,	**2005**		2004		2003	
	Number of Shares	**Amount**	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**346.2**	**2,282.4**	343.8	2,238.0	339.4	2,169.0
Exercise of stock options	**2.1**	**40.0**	2.0	33.4	3.6	51.9
Dividend Reinvestment and Share Purchase Plan	**0.4**	**14.6**	0.4	11.0	0.8	17.1
Issued for business acquisition	**0.2**	**6.8**	—	—	—	—
Balance at end of year	**348.9**	**2,343.8**	346.2	2,282.4	343.8	2,238.0

The fair value based method to expense stock options has been applied on a prospective basis since January 1, 2003. Stock-based compensation expense from fixed stock options and performance-based options is recognized in earnings over the vesting period with a corresponding increase in contributed surplus. Contributed surplus is decreased and share capital is increased for the proceeds from the exercise of these options.

Preferred Shares

The 5,000,000 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, preferential dividends of $1.375 per share per year, payable quarterly. Subsequent to December 31, 2005, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.50 if redeemed on

or prior to December 1, 2006; $25.25 if redeemed on or prior to December 1, 2007; and $25.00 if redeemed thereafter, in each case with all accrued and unpaid dividends to the redemption date.

Earnings Per Common Share

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 10.6 million shares (2004 — 10.6 million shares), resulting from the investment in Noverco.

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

(number of common shares in millions)

December 31,	**2005**	2004	2003
Weighted average shares outstanding	**337.4**	334.4	331.0
Effect of dilutive options	**3.8**	2.8	2.8
Diluted weighted average shares outstanding	**341.2**	337.2	333.8

For the year ended December 31, 2004, 1,750,800 stock options with a weighted average exercise price of $25.73 were excluded from the diluted earnings per share calculation. Stock options are excluded when the exercise price exceeds the average share price for the period. For the years ended December 31, 2005 and 2003, no stock options were excluded from the diluted earnings per share calculations.

Stock Split

On May 5, 2005, shareholders approved a two-for-one split of the common shares of the Company. All references to common shares, earnings per common share, diluted earnings per common share, stock options and performance stock units have been retroactively restated to reflect the impact of the stock split.

Dividend Reinvestment and Share Purchase Plan

Under the plan, registered shareholders may reinvest dividends in common shares of the Company or make optional cash payments to purchase additional common shares, in either case free of brokerage or other charges.

Shareholder Rights Plan

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

17. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains two plans for long-term incentive compensation: the Incentive Stock Option Plan (2002) and the Performance Stock Unit (PSU) Plan (2004). The Company's Incentive Stock Option Plan includes fixed stock options and performance-based stock options. A maximum of 30 million common shares are reserved for issuance under this plan. The PSU Plan grants notional units equivalent to one Enbridge common share.

Fixed Stock Options

Key employees are granted options to purchase common shares that are exercisable at the market price of the common shares at the date the options are granted. Generally, options vest in equal annual installments over a four-year period and expire ten years after the issue date. Outstanding stock options expire over a period ending

no later than June 16, 2015. Compensation expense recorded for the year ended December 31, 2005 for fixed stock options is $5.5 million (2004 — $3.7 million) and is included in operating and administrative expenses.

Outstanding Fixed Stock Options

(options in thousands; exercise price in dollars)

December 31,	2005		2004		2003	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**9,650**	**19.86**	9,482	17.98	10,084	16.08
Options granted	**1,533**	**31.70**	1,782	25.74	2,084	20.83
Options exercised	**(1,617)**	**17.51**	(1,558)	15.04	(2,488)	13.32
Options cancelled or expired	**(132)**	**26.39**	(56)	23.65	(198)	19.94
Options at end of year	**9,434**	**22.09**	9,650	19.86	9,482	17.98
Options vested	**5,248**		5,042		4,638	

Fixed Stock Option Characteristics

(options in thousands; exercise price in dollars)

December 31, 2005

	Options Outstanding			Options Vested	
Exercise Price Range	Number (000's)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number (000's)	Weighted Average Exercise Price
10.00 - 14.99	1,051	3.73	12.88	1,051	12.88
15.00 - 19.99	2,034	4.28	18.16	2,034	18.16
20.00 - 24.99	3,225	6.65	21.29	1,793	21.39
25.00 - 29.99	1,638	8.11	25.74	370	25.74
30.00 - 33.55	1,486	9.10	31.70	—	—
	9,434			5,248	

Performance-based Options

The Plan provides for the grant of performance-based options to executive officers that become exercisable when both performance targets and time requirements have been met. As of December 31, 2005, all performance targets have been met. Time requirements are fulfilled in equal annual installments over a five-year term. Options not yet vested will vest no later than September 2007.

Outstanding Performance-based Options

(options in thousands; exercise price in dollars)

December 31,	2005		2004		2003	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**2,555**	**20.68**	2,992	20.03	4,090	18.87
Options exercised	**(450)**	**16.51**	(437)	16.20	(1,098)	15.69
Options at end of year	**2,105**	**21.57**	2,555	20.68	2,992	20.03
Options vested	**1,457**	**20.87**	936	16.41	1,372	16.34

At December 31, 2005, the exercise prices of outstanding performance-based stock options ranged from $15.68 to $23.15 (2004 — $15.68 to $23.15; 2003 — $15.68 to $23.15). Outstanding performance-based stock options will expire over a period ending no later than September 16, 2010.

Performance Stock Units

During the year ended December 31, 2004 the Company implemented a PSU Plan for senior officers. Any cash awards under the PSU Plan are paid out at the end of a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's share price at the time and by a performance multiplier as determined by the Company's total shareholder return over the three-year performance period relative to a specified peer group of companies. The performance multiplier ranges from 0, if the Company's performance fails to meet threshold performance levels, to a maximum of 2, if the Company outperforms its peer group. During the three-year period, the number of PSUs outstanding is increased to include additional PSUs equal to the number of additional shares that would have been received had the PSUs been treated as shares enrolled in the Dividend Reinvestment Plan (DRIP).

Outstanding Performance Stock Units

December 31,	**2005**	2004
Units at beginning of year	**67,688**	—
Units granted	**130,130**	65,950
Units cancelled	**(3,265)**	—
DRIP	**6,099**	1,738
Units at end of year	**200,652**	67,688

Of the total PSUs outstanding at December 31, 2005, 69,766 units have a performance period ending March 8, 2007 and 130,886 units have a performance period ending January 1, 2008. Compensation expense recorded for the year ended December 31, 2005 for PSUs is $2.5 million (2004 — $0.5 million) and is included in operating and administrative expenses. An estimated performance multiplier of 1 (2004 — 1) has been used in determining the expense during the period based upon historical performance.

Pro forma Compensation Expense

If the Company had used the fair-value based method to account for fixed stock options and performance-based stock options granted in fiscal 2002, earnings and earnings per share would have been as follows:

(millions of dollars, except per share amounts)

Year ended December 31,	**2005**	2004	2003
Earnings applicable to common shareholders			
As reported	**556.0**	645.3	667.2
Total stock-based compensation expense[1]	**(12.0)**	(8.2)	(5.9)
Included as an expense in the statement of earnings[2]	**8.0**	4.2	1.9
Pro forma	**552.0**	641.3	663.2
Earnings per common share			
As reported	**1.65**	1.93	2.02
Pro forma	**1.64**	1.92	2.00
Diluted earnings per common share			
As reported	**1.63**	1.91	2.00
Pro forma	**1.62**	1.90	1.98

1. Total stock-based compensation expense if the fair value based method to expense all outstanding stock options had been applied since January 1, 2002.

2. Stock-based compensation recognized as an expense in the statement of earnings for options and performance stock units granted in 2003 through 2005 as a result of the adoption of the fair-value based method January 1, 2003.

The Black-Scholes model was used to calculate the fair value of fixed stock. Significant assumptions used in these models are as follows:

Year ended December 31,	**2005**	2004	2003
Fair value per option	**$ 5.31**	$ 3.85	$ 4.23
Valuation assumptions			
Expected option term (yrs)	**8**	8	8
Expected volatility	**16%**	15%	22%
Expected dividend yield	**3.17%**	3.54%	3.95%
Risk-free interest rate	**4.40%**	4.80%	5.24%

Contributed Surplus

(millions of dollars)

December 31,	**2005**	2004
Balance at beginning of year	**5.4**	1.9
Stock-based compensation	**5.5**	3.7
Option exercises	**(0.9)**	(0.2)
Balance at end of year	**10.0**	5.4

18. FINANCIAL INSTRUMENTS

Derivative Financial Instruments Used for Risk Management

The Company is exposed to movements in foreign currency exchange rates, interest rates and the price of energy commodities. In order to manage these exposures, the Company utilizes derivative financial instruments to create offsetting financial positions to specific underlying or cash market physical exposures. These exposures include the following:

Foreign Exchange

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar denominated investments and its Euro investment in CLH, where both carrying values and earnings are subject to foreign exchange risk. The Company utilizes par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure related to changes in carrying values. In addition, US$117.0 million (2004 — US$275.0 million) of cross currency swaps have been entered into to hedge the Company's exposure on its U.S. dollar denominated senior term notes. Long-term fixed rate debt of US$300.0 million (2004 — $ nil) has been designated as a hedge of U.S. dollar denominated foreign operations. The fair value of foreign exchange derivatives that are designated as hedges of foreign investments are recognized on the balance sheet, while all foreign exchange derivative instruments that are designated as cash flow hedges are accounted for on a settlement basis.

Interest Costs

The Company enters into forward interest rate agreements such as swaps and collars to convert floating rate debt to a fixed rate in order to hedge against the effect of future interest rate movements on its interest expense. The Company monitors its debt portfolio mix of fixed and variable rate instruments to ensure that it remains within the parameters of Board approved policy limits. In addition to the floating to fixed interest rate swaps, the Company has entered into fixed to floating interest rate swaps, with an aggregate notional amount of $300.0 million (2004 — $300.0 million), to manage its balance of fixed and floating rate debt.

Energy Commodity Costs

The Company uses gas price swaps, futures, options and collars to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector pipelines. The Company also uses derivative instruments to fix the value of variable price exposures that arise from commodity storage arrangements and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable, it is exposed to the price differential between natural gas and NGLs. This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of natural gas and NGLs are fixed with swaps, or capped or collared with options.

The Company has also entered into over-the-counter swap agreements that convert the price of power in Alberta and Ontario from a floating rate to a fixed rate per megawatt hour (MW/H) or convert fixed rate power to a floating rate.

Natural Gas Supply Management

The Company hedges a portion of the cost of future natural gas supply requirements of EGD, on behalf of its ratepayers, as allowed by the regulator. Amounts paid or received under the agreements are recognized as part of the cost of the natural gas purchases and are recovered through the ratemaking process. At December 31, 2005, the Company had entered into natural gas price swaps and options to manage the price for approximately 20.7%, or 27.3 billion cubic feet(bcf), of its forecast fiscal 2006 system gas supply.

Credit Risk

Entering into derivative financial instruments can give rise to additional credit risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company minimizes credit risk by entering into risk management transactions only with institutions that possess investment grade credit ratings or have provided the Company with an acceptable form of credit enhancement. For transactions with terms greater than five years, the

Company may also retain the right to require a counterparty that would otherwise meet the Company's credit criteria, to provide collateral.

Fair Values

The fair values of derivatives have been estimated using year-end market information. These fair values approximate the amount that the Company would receive or pay to terminate the contracts.

(millions of dollars unless otherwise noted)

December 31,	**2005**			2004		
	Notional Principal or Quantity	**Fair Value Receivable/ (Payable)**	**Maturity**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**307.3**	**(2.9)**	**2007-2022**	535.8	(51.1)	2005-2022
Euro cross currency swaps[1]	**447.6**	**39.6**	**2006-2019**	493.5	(51.3)	2005-2019
Forwards (cumulative exchange amounts)[2]	**1,640.1**	**241.6**	**2006-2022**	1,740.3	181.0	2005-2022
Interest rates						
Interest rate swaps	**954.4**	**(1.1)**	**2006-2029**	1,069.0	1.5	2005-2029
Forward interest rate swaps	**150.0**	**1.2**	**2007**	200.0	—	2006
Energy commodities						
Natural gas (bcf)	**130.5**	**18.1**	**2006-2011**	107.8	(1.0)	2005-2010
Natural gas supply (bcf)	**27.3**	**(6.7)**	**2006**	34.9	(28.1)	2005
Power (MW/H)	**28.0**	**0.8**	**2006-2017**	—	—	—

1. Included in Deferred Amounts and Other Assets for qualifying hedges of foreign operations.

2. Includes $160.6 million (2004 — $128.2 million) in Deferred Amounts and Other Assets for qualifying hedges of foreign operations.

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $91.0 million (2004 — $214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2007. The contracts are not effective hedges for accounting purposes but provide an economic hedge of an exposure related to income taxes on foreign currency gains or losses on Canadian dollar debt of a U.S. subsidiary. These instruments are recorded at fair value and have a fair value payable of $14.3 million as at December 31, 2005 (2004 — $28.8 million).

The Company has a net positive fair market value of $352.4 million to its derivative counterparties, as such the Company is exposed to replacement cost risk if these counterparties failed to perform obligations under these contracts. The Company has no significant concentration with any single counterparty and only transacts with highly credit worthy counterparties.

Interest Rate Management

The derivative instruments used to manage interest rate risk and the associated debt related to these instruments are as follows:

(millions of dollars)

December 31, 2005	Maturity	Effective Interest Rate[1]	Notional Amounts
Liquids Pipelines			
Commercial paper (floating to fixed interest swap)	2029	6.0%	25.4
Corporate			
Commercial paper (floating to fixed interest swap)	2006	2.8%	400.0
Commercial paper (floating to fixed interest swap)	2006-2009	4.0%	US$ 196.5
Senior term notes (cross currency swap)	2007	7.5%	US$ 117.0
Medium term notes 5.45% (fixed to floating interest swap)	2006	floating	300.0

Fair Values of Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties, calculated at the reporting date, to settle these instruments. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The fair value of other financial instruments reflect the Company's best estimate and are based on the Company's valuation techniques or models to estimate market values.

Total Debt

(millions of dollars)

December 31,	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**1,039.4**	**1,201.4**	913.4	1,037.8
Gas Distribution and Services	**1,786.7**	**2,184.2**	1,823.4	2,168.9
Corporate	**3,854.2**	**4,076.3**	4,020.4	4,275.6
	6,680.3	**7,461.9**	6,757.2	7,482.3

The fair value of debt does not include the effects of hedging. Non-recourse debt has a carrying value of $1,688.1 million (2004 — $695.4 million) and a fair value of $1,775.1 million (2004 — $769.4 million).

Trade Credit Risk

Trade receivables related to Liquids Pipelines consist primarily of amounts due from companies operating in the oil and gas industry and are collateralized by the crude oil and other products contained in the Company's pipelines and storage facilities. Trade receivables in Gas Pipelines and Sponsored Investments also consist primarily of amounts due from companies in the oil and gas industry, where shippers fail to maintain specified credit ratings they are required to provide letters of credit or other suitable security. Credit risk in the Gas Distribution and Services segment is reduced by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. Included in accounts receivable is an allowance for doubtful accounts of $41.4 million at December 31, 2005 (2004 — $45.5 million).

19. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars)

Year ended December 31,	2005	2004	2003
Earnings before income taxes	**784.2**	941.4	846.7
Combined statutory income tax rate	**35.2%**	35.5%	36.7%
Income taxes at statutory rate	**276.0**	334.2	310.7
Increase/(decrease) resulting from:			
Tax rate changes on future income tax balances	**1.2**	42.7	6.2
Future income taxes related to regulated operations	**(17.5)**	(13.7)	(35.6)
Non-taxable items, net	**(41.6)**	(72.7)	(99.2)
Lower foreign tax rates	**(9.1)**	(15.1)	(21.1)
Large Corporations Tax in excess of surtax	**12.3**	10.0	15.3
Other	**—**	3.8	(3.7)
Income Taxes	**221.3**	289.2	172.6
Effective income tax rate	**28.2%**	30.7%	20.4%

In 2005, income taxes paid amounted to $150.3 million (2004 — $243.2 million; 2003 — $202.9 million).

Components of Future Income Taxes

(millions of dollars)

December 31,	2005	2004
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	**567.0**	425.3
Differences in accounting and tax bases of investments	**356.1**	323.0
Other	**230.6**	197.2
	1,153.7	945.5
Future Income Tax Assets		
Loss carryforwards	**230.2**	207.5
Other	**49.4**	85.7
	279.6	293.2
Total Net Future Income Tax Liability	**874.1**	652.3

At December 31, 2005, the Company has recognized the benefit of unused tax loss carryforwards of $660.8 million (2004 — $596.4 million). Unused tax loss carryforwards expire as follows; 2006 - $9.9 million; 2007 — $16.2 million; 2008 — $19.7 million; 2009 — $7.2 million; 2010 — $4.3 million; 2011 — $8.3 million, and 2014 — $2.6 million and 2015 and beyond — $592.6 million.

Geographic Components of Pretax Earnings and Income Taxes

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Earnings before income taxes			
Canada	**487.3**	682.9	651.5
United States	**150.5**	123.2	40.1
Other	**146.4**	135.3	155.1
	784.2	941.4	846.7
Current income taxes			
Canada	**106.9**	267.4	93.7
United States	**—**	5.0	(10.9)
Other	**6.3**	4.1	4.0
	113.2	276.5	86.8
Future income taxes			
Canada	**49.4**	(18.3)	116.6
United States	**58.7**	30.6	(31.0)
Other	**—**	0.4	0.2
	108.1	12.7	85.8
Current and future income taxes	**221.3**	289.2	172.6

20. POST-EMPLOYMENT BENEFITS

Pension Plans

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits or both for employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide non-contributory defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides non-contributory defined benefit pension benefits for U.S. based employees. The Company has four supplemental pension plans which provide pension benefits that exceed those benefits earned in the basic plans.

Defined Benefit Plans

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

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	January 1, 2004	January 1, 2007
Enbridge U.S.	January 1, 2005	January 1, 2006
Gas Distribution and Services	January 1, 2005	January 1, 2008

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

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, pension costs equal amounts required to be contributed by the Company. Pension costs in respect of these plans during the year were $2.4 million (2004 — $2.3 million; 2003 — $2.0 million).

Post-employment Benefits Other than Pensions

Post-employment benefits other than pensions (OPEB) include primarily supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

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

	OPEB		Pension Benefit	
(millions of dollars)	**2005**	2004	**2005**	2004
Change in accrued benefit obligation				
Benefit obligation, January 1	**170.3**	155.7	**847.9**	788.3
Service cost	**4.4**	4.0	**25.5**	22.7
Interest cost	**10.5**	9.4	**52.7**	49.4
Amendments	**(5.8)**	(2.2)	**—**	0.7
Employee contributions	**0.4**	0.4	**—**	—
Actuarial loss	**20.4**	13.5	**159.0**	30.4
Benefits paid	**(5.8)**	(5.4)	**(41.7)**	(38.9)
Other	**—**	—	**—**	3.3
Effect of exchange rate changes	**(2.8)**	(5.1)	**(4.1)**	(8.0)
Benefit obligation, December 31	**191.6**	170.3	**1,039.3**	847.9
Change in plan assets				
Fair value of plan assets, January 1	**40.2**	36.2	**1,061.8**	986.7
Actual return on plan assets	**1.0**	1.7	**161.9**	110.0
Employer's contributions	**8.7**	9.9	**14.2**	14.5
Employee contributions	**0.4**	0.4	**—**	—
Benefits paid	**(5.8)**	(5.4)	**(41.7)**	(38.9)
Other	**—**	—	**(0.9)**	(0.8)
Effect of exchange rate changes	**(1.2)**	(2.6)	**(4.2)**	(9.7)
Fair value of plan assets, December 31	**43.3**	40.2	**1,191.1**	1,061.8
Funded status				
Benefit obligation, December 31	**(191.6)**	(170.3)	**(1,039.3)**	(847.9)
Fair value of plan assets, December 31	**43.3**	40.2	**1,191.1**	1,061.8
Overfunded/(Underfunded) status, December 31	**(148.3)**	(130.1)	**151.8**	213.9
Contribution after measurement date	**0.8**	—	**—**	2.9
Unamortized prior service cost	**—**	0.4	**14.5**	17.2
Unamortized transitional obligation/(asset)	**14.7**	24.2	**(22.0)**	(24.1)
Unamortized net loss	**57.2**	38.9	**118.3**	26.0
Net amount recognized, December 31	**(75.6)**	(66.6)	**262.6**	235.9

The table above reflects the funded status and recorded pension and OPEB assets and liabilities for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a cash basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits. Using the cash basis for the Gas Distribution and Services plans and the accrual method for all other plans, the Company's net pension asset was $70.8 million (2004 — $72.9 million). The net OPEB liability was $15.4 million (2004 — $11.8 million). These net assets or liabilities are recorded on the balance sheet in Deferred Amounts and Other Assets with the current portion recorded in working capital accounts.

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

	OPEB			Pension Benefits		
Year ended December 31,	**2005**	2004	2003	**2005**	**2004**	2003
Discount rate	**5.30%**	6.21%	6.31%	**5.24%**	**6.26%**	6.29%
Average rate of salary increases				**4.44%**	**4.00%**	4.00%

Net Pension Plan and OPEB Costs Recognized

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Benefits earned during the year	**32.3**	29.0	27.7
Interest cost on projected benefit obligations	**63.2**	58.8	57.4
Actual return on plan assets	**(162.9)**	(111.7)	(110.5)
Difference between actual and expected return on plan assets	**87.3**	41.1	45.7
Amortization of prior service costs	**2.3**	2.3	2.8
Amortization of transitional obligation	**0.2**	0.1	0.5
Amortization of actuarial loss	**9.6**	12.2	12.0
Special Termination Benefits	**—**	3.3	—
Amount charged to EEP	**(10.2)**	(7.8)	(10.2)
Pension and OPEB cost recognized	**21.8**	27.3	25.4

The above table reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a pay-as-you-go basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Gas Distribution and Services plans and the accrual method for all other plans, the Company's pension cost was $11.6 million (2004 — $11.6 million; 2003 — $9.4 million), and its OPEB cost was $5.9 million for 2005 (2004 — $5.8 million; 2003 — $7.0 million)

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

	OPEB			**Pension Benefits**		
Year ended December 31,	**2005**	2004	2003	**2005**	2004	2003
Discount rate	**6.21%**	6.31%	6.79%	**6.26%**	6.29%	6.75%
Average rate of salary increases				**4.00%**	4.00%	4.00%
Average rate of return on pension plan assets	**4.50%**	4.50%	4.50%	**7.31%**	7.32%	7.25%

Medical Cost Trend Rates

The assumed medical cost trend rates for the next year used to measure the expected cost of benefits and the ultimate trend rate and the year in which the ultimate trend rate is assumed to be achieved are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	5%	2016
Other Medical and Dental	5%	5%	2006
Enbridge U.S.	12%	5%	2012

A one percent increase in the assumed medical and dental care trend rate would result in an increase of $32.8 million in the accumulated post-employment benefit obligations and an increase of $2.6 million in benefit and interest costs. A one percent decrease in the assumed medical and dental care trend rate would result in a decrease of $26.0 million in the accumulated post-employment benefit obligations and a decrease of $2.0 million in benefit and interest costs.

Major Categories of Plan Assets

(millions of dollars)	OPEB				Pension Benefit			
Year ended December 31,		**2005**		2004		**2005**		2004
	Target	**%**	**Amount**	%	**Target**	**%**	**Amount**	%
Equity securities	0.0%	**0.0%**	**—**	—	**60.0%**	**58.8%**	**778.4**	58.7%
Fixed income securities	100.0%	**84.8%**	**36.7**	84.1%	**40.0%**	**31.7%**	**419.9**	37.0%
Other	0.0%	**15.2%**	**6.6**	15.9%	**0.0%**	**9.5%**	**125.2**	4.3%
Total Assets	100.0%	**100.0%**	**43.3**	100.0%	**100.0%**	**100.0%**	**1,323.5**	100.0%
Assets attributable to former Affiliates			**—**				**(132.4)**	(115.1)
			43.3				**1,191.1**	(114.1)

Plan assets are invested primarily in readily marketable investments with thresholds on the credit quality of fixed income securities.

Expected Rate of Return on Plan Assets

	OPEB		Pension Benefit	
Year ended December 31,	**2005**	2004	**2005**	2004
Canadian Plans	**4.50%**	4.50%	**7.25%**	7.25%
United States Plan	**4.50%**	4.50%	**7.75%**	7.75%

The Company manages the investment risk of its pension funds by setting a long term asset mix policy for each pension fund after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Plan Contributions by the Company

(millions of dollars)	OPEB		Pension Benefit	
Year ended December 31,	**2005**	2004	**2005**	2004
Total contributions	**8.7**	9.9	**14.2**	14.5
Contributions expected to be paid in 2006	**5.8**		**17.4**	

Benefits Expected to be Paid by the Company

(millions of dollars)

Year ended December 31,	2006	2007	2008	2009	2010	2011 - 2015
Expected future benefit payments	45.3	46.6	48.1	49.7	51.7	292.1

21. OTHER INVESTMENT INCOME

(millions of dollars)

Year ended December 31,	2005	2004	2003
Cost investments	**50.9**	84.0	67.2
Interest income	**23.2**	25.8	32.9
Gain on reduction of EEP ownership interest	**24.5**	19.7	50.0
Non-controlling interest in EEM	**(12.4)**	(20.2)	(25.9)
Gain on reduction of AltaGas ownership interest	**—**	9.9	—
Allowance for equity funds used during construction	**0.9**	0.9	3.2
Gain/(loss) on foreign currency contracts	**6.8**	(21.3)	(87.2)
Other	**20.9**	2.6	(4.8)
	114.8	101.4	35.4

22. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of dollars)

Year ended December 31,	2005	2004	2003
Accounts receivable and other	**(441.4)**	(347.4)	(346.9)
Inventory	**(215.7)**	35.3	(232.4)
Deferred amounts and other assets	**(133.7)**	(94.2)	(78.9)
Accounts payable and other	**394.8**	278.3	93.9
Interest payable	**(1.4)**	(13.1)	(5.5)
	(397.4)	(141.1)	(569.8)

Changes in accounts payable exclude changes in construction payables which are investing activities.

23. RELATED PARTY TRANSACTIONS

Neither EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. Vector Pipeline uses the services of Enbridge to operationally manage its business. Amounts for these services, which are charged at cost in accordance with service agreements are:

(millions of dollars)

Year ended December 31,	2005	2004	2003
EEP	**184.7**	173.0	128.9
EIF	**—**	9.4	4.7
Vector Pipeline	**4.1**	4.4	3.3
	188.8	186.8	136.9

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline Canada and Vector Pipeline. EGD is charged market prices for these services:

(millions of dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline Canada	**40.4**	50.6	40.7
Vector Pipeline	**29.2**	39.1	23.2
	69.6	89.7	63.9

CustomerWorks Limited Partnership (CustomerWorks), a joint venture, provides customer care services to EGD under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services. CustomerWorks also rents an automated billing system from ECS, a subsidiary of the Company. Amounts charged by (to) CustomerWorks:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
EGD	**103.6**	127.0	95.5
ECS	**(8.7)**	(22.5)	(25.5)
	94.9	104.5	70.0

Enbridge Gas Services Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP.

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Enbridge Gas Services Inc.			
Purchases	**48.1**	30.7	33.6
Sales	**(4.7)**	(8.8)	(1.3)
	43.4	21.9	32.3

Enbridge Gas Services Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts paid are as follows:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Alliance Pipeline Canada	**9.1**	8.8	8.4
Vector Pipeline	**0.7**	0.5	0.6
	9.8	9.3	9.0

Enbridge Gas Services (US) Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline US and Vector Pipeline. Amounts paid are as follows:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Alliance Pipeline US	**7.1**	7.6	7.8
Vector Pipeline	**9.5**	9.8	10.5
	16.6	17.4	18.3

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP.

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Purchases	**9.7**	—	—
Sales	**—**	(2.3)	—
	9.7	(2.3)	—

The receivable from affiliate of $177.0 million (2004 — $171.7 million) resulted from the sale of Enbridge Midcoast Energy to EEP. The note, denominated in U.S. dollar, bears interest at 6.6% and matures in 2007. The balance on December 31, 2005 was US$151.9 million (2004 — US$142.1 million). Interest income related to the affiliate receivable was $11.7 million (US$9.4 million), $11.8 million (US$9.0 million) and $21.7 million (US$15.5 million), in 2005, 2004 and 2003, respectively. The fair value of the receivable at December 31, 2005 is $176.8 million.

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates.

Prices are determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

24. COMMITMENTS AND CONTINGENCIES

Enbridge Gas Distribution Inc.

Class Action Lawsuit — late payment penalties

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against EGD by a customer with respect to late payment penalties. The Supreme Court of Canada determined that EGD would be required to repay a portion of amounts paid to it as late payment penalties from April 1994. The total amount of late payment penalties billed between April 1994 and February 2002 (when EGD's late payment penalty was revised), was approximately $74 million, of which a portion may be eligible for repayment. The amount payable is not determinable at this time. The Supreme Court has directed that a lower court determine the amount payable. Case conferences were held before a judge of the Ontario Supreme Court in August and December 2004 and March 2005 to discuss the remaining outstanding issues following the Supreme Court's decision. Further court proceedings to determine the amount payable and other related issues are likely to be held in early 2006.

Late payment penalty revenues are included in EGD's estimate of revenues for the year and therefore accrue to the benefit of all customers, reducing the cost of providing distribution services. The OEB approves these estimates and the resulting rates each year. EGD intends to apply to the OEB for recovery of any amount payable that results from this action.

Bloor Street Incident

EGD has 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. The maximum possible fine upon conviction on all charges would be $5.0 million in aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion has also been called, but the proceedings are stayed pending resolution of the TSSA and OHSA matters. The courts have not yet ruled upon any of the charges laid under the TSSA or the OHSA, and thus it is not possible at this time to predict or comment upon the potential outcome. The trial in respect of these charges commenced January 3, 2006. EGD does not expect the outcome of these civil actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

The remediation of discontinued manufactured gas plant sites may result in future costs to EGD. In October 2002, a claim was filed for $55 million in damages relating to a certain manufactured gas plant site. EGD filed a statement of defence in June 2003 denying liability. Trial scheduling court is expected to occur in early 2006 and it is possible that a trial in the matter may take place in 2006. Although management believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance may be recovered through rates. As such, management does not believe that the outcome will have any material financial impact.

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced a class action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. The Plaintiffs have filed a motion to establish a cause of action, one of the requirements to have the motion certified as a class action under the *Class Proceedings Act* (Ontario). These

matters are currently before the Ontario District Court for hearing. Since the outcome is indeterminable, the Company has made no provision at this time for any potential liability.

Enbridge Energy Company, Inc.

Enbridge Energy Company, Inc. (EEC), a subsidiary of the Company, is the general partner of EEP, EEC's former subsidiary Enbridge Midcoast Energy Inc. (Midcoast) has been assessed by the U.S. Internal Revenue Service (IRS) taxes, interest and penalties of US$4.5 million for its 1999 through 2001 taxation years. Midcoast has paid all amounts and has filed a claim for refund of the full amount. The IRS has challenged Midcoast's tax treatment of its 1999 acquisition of several partnerships that owned a natural gas pipeline system in Kansas (these assets were sold to EEP in 2002). The IRS position, if sustained, could decrease the U.S. tax basis for the pipeline assets, which could reduce Enbridge's earnings by up to approximately US$60 million, although the immediate cash tax impact would be significantly less. Enbridge believes the tax treatment of the acquisition and related tax deductions claimed were appropriate. Enbridge intends to vigorously litigate this matter in U.S. District Court (Houston) beginning in February 2006.

Enbridge and its subsidiaries maintain reserves for income taxes, which include amounts estimated to be adequate to compensate for contingent liabilities arising from tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

Olympic Pipe Line Company

On December 12, 2005 the Company announced that it will acquire a 65% common share interest in the Olympic Pipe Line Company for US$99.8 million subject to working capital adjustments. The transaction closed on February 1, 2006.

25. GUARANTEES

EEC, as the general partner of EEP, has agreed to indemnify EEP from and against substantially all liabilities including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance, or to any liabilities relating to a change in laws after December 27, 1991.

In addition, in the event of default, EEC, as the general partner, is subject to recourse with respect to a portion of EEP's long-term debt, which amounts to US$186.0 million at December 31, 2005 (2004 — US$217.0 million).

In the normal course of conducting business, Enbridge, enters into a wide variety of agreements which provide for indemnification to third parties. Enbridge cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements however historically, Enbridge has not made any significant payments under these indemnification provisions. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples where such indemnification obligations have been issued include:

Sale Agreements for Assets or Businesses

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements

- breaches of representations, warranties or covenants;
- changes in laws;
- failure to satisfy certain performance standards;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

26. UNITED STATES ACCOUNTING PRINCIPLES

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

Earnings and Comprehensive Income

(millions of dollars, except per share amounts)

Year ended December 31,	**2005**	2004	2003
Earnings under Canadian GAAP	**556.0**	645.3	667.2
Stock-based compensation[1]	**(16.6)**	—	—
Loss on ineffective hedges[4]	**—**	—	(53.8)
Tax effect of the above adjustments	**—**	—	21.5
Earnings under U.S. GAAP	**539.4**	645.3	634.9
Unrealized net gain/(loss) on cash flow hedges[5]	**72.3**	(32.9)	66.9
Reclassification adjustment on cash flow hedges[5]	**—**	—	80.6
Foreign currency translation adjustment[5]	**(20.7)**	2.4	(159.6)
Comprehensive income	**591.0**	614.8	622.8
Earnings per common share	**1.60**	1.93	1.92
Diluted earnings per common share	**1.58**	1.92	1.90

Financial Position

(millions of dollars)

	December 31, 2005		December 31, 2004	
	Canada	**United States**	Canada	United States
Cash[6]	**153.9**	**153.9**	105.5	120.3
Accounts receivable and other[4,5,6]	**1,900.3**	**1,991.5**	1,451.9	1,483.6
Property, plant and equipment, net[6]	**10,466.6**	**10,466.6**	9,066.5	10,334.1
Long-term investments[6]	**1,842.8**	**1,842.8**	2,278.3	1,898.1
Deferred amounts[2,6]	**894.2**	**2,086.6**	729.2	1,699.2
Intangible assets[6]	**252.6**	**252.6**	133.9	242.2
Goodwill[6]	**367.2**	**367.2**	31.5	339.6
Accounts payable and other[1,4,5,6]	**1,624.8**	**1,671.0**	1,275.9	1,375.8
Current maturities and short-term debt[5,6]	**401.2**	**401.2**	703.9	715.2
Current portion of non-recourse debt[6]	**68.2**	**68.2**	30.2	71.7
Long-term debt[4,5,6]	**6,279.1**	**6,279.8**	6,053.3	6,264.9
Non-recourse long-term debt[6]	**1,619.9**	**1,619.9**	665.2	1,503.5
Other long-term liabilities[6]	**91.7**	**91.7**	151.8	158.5
Future income taxes[2,4,5,6]	**874.1**	**2,162.2**	652.3	1,638.9
Non-controlling interests[6]	**691.0**	**691.0**	514.9	689.9
Retained earnings	**2,098.2**	**2,027.6**	1,840.9	1,770.3
Contributed surplus[1]	**10.0**	**2,218.7**	5.4	—
Additional paid in capital[1]	**—**	**53.9**	—	27.3
Foreign currency translation adjustment[5]	**(171.8)**	**—**	(139.8)	—
Accumulated other comprehensive loss[5]	**—**	**(95.5)**	—	(147.1)

1. *Stock-based Compensation*

Effective January 1, 2003, the Company adopted FAS 123, Accounting for Stock-Based Compensation, on a prospective basis for U.S. GAAP, and elected to use the fair value-based method to measure compensation expense for all options issued after January 1, 2003. The adoption of the fair value method for U.S. GAAP eliminates all differences between Canadian and U.S. GAAP for options granted subsequent to the date of adoption. Disclosure differences in pro forma earnings between Canadian and U.S. GAAP will remain for those options granted prior to adoption, on January 1, 2002, of the Canadian accounting standard for stock-based compensation. Earnings differences will remain for performance-based options granted during 2002 when they vest.

Prior to the adoption of FAS 123, the Company accounted for stock-based compensation for U.S. GAAP in accordance with APB 25, Accounting for Stock Issued to Employees, which required the use of the intrinsic value-based method to measure compensation expense. Under U.S. GAAP, 1,620,000 of the 2002 issuance of performance-based options vested during 2005 resulting in a pre-tax compensation expense of $16.6 million (2004 — nil).

2. *Future Income Taxes*

Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. A deferred tax liability of $654.1 million (2004 — $596.8 million) is recorded for U.S. GAAP purposes and reflects the difference between the accounting basis and the tax basis of property, plant and equipment. Regulated companies following the taxes payable method are not required to record this additional tax liability under Canadian GAAP. To recover the additional deferred income taxes recorded under U.S. GAAP through the ratemaking process, it would be necessary to record incremental revenue of $538.3 million (2004 — $333.1 million).

3. *Accounting for Joint Ventures*

U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for joint ventures need not be reconciled from Canadian to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity.

4. *Financial Instruments*

For U.S. GAAP purposes, FAS 133, Accounting for Derivative Instruments and Hedging Activities, requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the fair value of derivatives are recognized in current period earnings unless specific hedge accounting criteria are met.

The accounting for changes in the fair value of derivatives held for hedging purposes depends upon their intended use. For fair value hedges, the effective portion of changes in the fair value of derivative instruments is offset in income against the change in fair value, attributed to the risk being hedged, of the underlying hedged asset, liability or firm commitment. For cash flow hedges, the effective portion of changes in the fair value of derivative instruments is offset through other comprehensive income (or loss), until the variability in cash flows being hedged is recognized in earnings in future accounting periods.

5. Accumulated Other Comprehensive Loss

At December 31, 2005, Accumulated Other Comprehensive Loss of $95.5 million consists of an accumulated foreign currency translation balance of $149.8 million (2004 — $129.1 million) and net unrealized gains of $54.3 million (2004 — losses of $18.0 million). For U.S. GAAP purposes, the foreign currency translation adjustment balance is classified as a component of Accumulated Other Comprehensive Loss. The fair value of derivative financial instruments that qualify as cash flow hedges are also included in Accumulated Other Comprehensive Loss.

Of the total Accumulated Other Comprehensive Loss of $95.5 million, the Company estimates that approximately $10.4 million, representing unrecognized net gains on derivative activities at December 31, 2005, is expected to be reclassified into earnings during the next twelve months and primarily relates to natural gas supply management.

6. Consolidation of Variable Interest Entities

On December 24, 2003, the Financial Accounting Standards Board issued a revision to FASB Interpretation (FIN) 46, which replaces the interpretation released in January 2003.

FIN 46R requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest. The Company is the primary beneficiary of EIF through a combination of the 41.9% equity interest and the preferred unit interest. Effective January 1, 2005, the Company adopted without restatement of prior periods the new CICA accounting guideline for Consolidation of Variable Interest Entities (AcG 15). AcG 15 and FIN46R do not create U.S. GAAP differences for the Company, therefore there is not a U.S. GAAP difference related to variable interest entities at December 31, 2005. The impact of FIN 46R included in the U.S. GAAP amounts at and for the year ended December 31, 2004 are outlined below:

Exhibit 99.5

Management's Discussion and Analysis
Enbridge Inc.

CONSOLIDATED RESULTS

FINANCIAL HIGHLIGHTS[1]

(millions of Canadian dollars, except per share amounts)	**2005**	2004	2003
Liquids Pipelines	**229.1**	219.9	213.5
Gas Pipelines	**59.8**	53.8	70.1
Sponsored Investments	**64.8**	66.2	234.3
Gas Distribution and Services[2,3]	**178.8**	313.1	153.6
International	**87.4**	73.6	72.3
Corporate	**(63.9)**	(81.3)	(76.6)
Earnings Applicable to Common Shareholders	**556.0**	645.3	667.2
Earnings Per Common Share	**1.65**	1.93	2.02
Diluted Earnings Per Common Share	**1.63**	1.91	2.00
Dividends Per Common Share[4]	**1.0375**	0.92	0.83
Common Share Dividends	**361.1**	315.8	283.9
Total Assets	**17,210.9**	14,905.1	13,945.0
Total Long-Term Liabilities	**9,690.7**	8,182.5	8,028.2

1. Financial Highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.
2. The reported results for the year ended December 31, 2004 include earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution (EGD), Noverco and other gas distribution entities. This resulted from the elimination of the quarter lag basis of consolidation in 2004, described below.
3. The reported results for the year ended December 31, 2003 include earnings for the 12 months ended September 30, 2003 for these entities.
4. All per share amounts have been restated to reflect the Company's two-for-one stock split in May 2005.

Earnings applicable to common shareholders are $556.0 million for the year ended December 31, 2005, or $1.65 per share, compared with $645.3 million, or $1.93 per share, in 2004. The $89.3 million decrease in earnings is primarily the result of the sale of the investment in AltaGas in 2004, which had resulted in an after-tax gain of $97.8 million as well as the absence of its earnings. Earnings for 2004 also included 15 months of earnings for gas distribution utilities, reflecting the change in year end for those entities. Positive factors in 2005 include the earnings contribution from the recently acquired Enbridge Offshore Pipelines, higher contribution from the gas distribution utility and lower interest expense.

Earnings applicable to common shareholders for the year ended December 31, 2004 were $645.3 million, or $1.93 per share compared with $667.2 million, or $2.02 per share, for the year ended December 31, 2003. In addition to the factors noted above, the 2004 results included a full year of incremental earnings from the Terrace Phase III mainline expansion, rate increases

and positive variances from forecast costs in Enbridge Gas Distribution, and improved fractionation margins in Aux Sable compared with 2003. These positive factors in 2004 were offset by the absence of earnings from Alliance Pipeline Canada and Enbridge Saskatchewan, which were sold in June 2003 to Enbridge Income Fund for a gain of $169.1 million.

Significant non-operating factors and variances affecting consolidated earnings are:

(millions of Canadian dollars)	**2005**	2004	2003
Sponsored Investments			
Dilution gains on the issue of Enbridge Energy Partners (EEP) units	**8.9**	7.6	20.3
EEP non-cash derivative fair value losses	**(5.0)**	—	—
Gain on sale of assets to Enbridge Income Fund (EIF)	**—**	—	169.1
Gas Distribution and Services			
Gain on sale of investment in AltaGas Income Trust	**—**	97.8	—
Calendar year basis adjustment[1]	**—**	27.1	—
Calendar year basis adjustment[2]	**—**	—	(4.0)
Colder/(warmer) than normal weather	**—**	21.3	33.9
Impairment loss on Calmar gas plant	**—**	(8.2)	—
Regulatory disallowances	**—**	—	(35.2)
EGD unbilled revenue	**—**	—	33.6
Dilution gain in Noverco (Gaz Metro unit issuance)	**7.3**	—	7.1
Dilution gain — AltaGas Income Trust	**—**	8.0	—
Revalue future income taxes due to tax rate changes	**—**	0.6	(52.1)
International			
Gain on land sale in CLH	**7.6**	—	—
Corporate			
Revalue future income taxes due to tax rate changes	**—**	—	(1.0)
Total significant non-operating factors and variances increasing earnings	**18.8**	154.2	171.7

1. Effective December 31, 2004, EGD changed its fiscal year-end from September 30 to December 31. Consequently, the reported consolidated results for the year ended December 31, 2004 included EGD's results for the fifteen months ended December 31, 2004. The adjustment above deducts EGD's results for the three months ended December 31, 2003, to reflect EGD's 2004 earnings on the calendar basis, consistent with 2005. As a result, this adjustment differs from the adjustment reported in 2004.

2. This adjustment reflects EGD's 2003 earnings on the calendar basis. Prior to EGD's change in fiscal year end in 2004, described above, EGD's earnings were consolidated on a one-quarter-lag basis. As a result, reported consolidated results for the year ended December 31, 2003 included EGD's results for the twelve months ended September 30, 2003. This presentation differs from the presentation in the 2004 Management's Discussion and Analysis.

Significant operating factors affecting earnings in 2005 include:

- Enbridge Offshore Pipelines, acquired December 31, 2004, contributes positive earnings.
- EGD earnings are higher due to higher rate base and a number of smaller favourable variances across the utility.
- There are no earnings from AltaGas in 2005 as the investment was sold in 2004.
- Corporate costs are lower primarily as a result of lower interest expense.

Enbridge completed several strategic initiatives during 2005:

- Negotiated new five year Incentive Tolling Settlement on the Enbridge System.
- Obtained founding shipper agreements underpinning the $400 million Waupisoo Pipeline and filed an application for regulatory approval.
- Confirmed shipper support for both the Gateway Petroleum Export Pipeline and the Gateway Condensate Import Pipeline, through non-binding open seasons, supporting continued preparations to file a full regulatory application in 2006.
- Secured the BA Energy Upgrader $80 million terminaling and pipeline services agreement as the initial customer for our new Stonefell terminal at Fort Saskatchewan, Alberta.
- Substantially completed the US$190 million Spearhead Pipeline project to deliver Canadian crude oil, for the first time, down to the major hub at Cushing, Oklahoma.
- Secured shipper support and commenced field work for the US$950 million, 400,000 bpd Southern Access mainline expansion project being undertaken by Enbridge and Enbridge Energy Partners.
- Entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all of the power to be produced from the $400 million, 200-megawatt wind power project currently under development by Enbridge on the shores of Lake Huron.
- Entered into an agreement to purchase 65% of the Olympic Pipe Line Company, a refined products pipeline in Washington State, for US$99.8 million.

Enbridge (the Company) has foreign currency denominated earnings, primarily from U.S. based operations and investments, as well as its Euro investment in CLH. The Company uses long-term derivative contracts to economically hedge a significant portion of the cash distributions from these long-term investments. However, this does not eliminate the GAAP earnings volatility caused by exchange rate differences. During the year ended December 31, 2005, the Company received foreign currency denominated cash distributions and settled associated hedge transactions resulting in $13.0 million (2004 — $7.5 million) of incremental cash flows, which is not included in reported earnings.

CORPORATE STRATEGY

Corporate Vision and Objective

Enbridge is an energy delivery company that delivers natural gas and crude oil, which are used 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 objective is to generate long-term value for investors. The key elements of this vision are to:

- generate above industry-average annual earnings per share growth;
- maintain a stable, low risk investment profile and strong financial position; and
- deliver superior returns (dividends and capital appreciation) to shareholders.

Core Businesses

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

- Liquids Pipelines, which owns and operates the Canadian portion of the world's longest crude oil pipeline system and includes other common carrier and feeder liquids pipelines, including the Athabasca System;
- Gas Pipelines, which includes the Company's interests in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines;
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF) and Enbridge Energy Partners, L.P. (EEP), both managed by Enbridge;
- Gas Distribution and Services, which includes Enbridge Gas Distribution (EGD), the largest gas distribution utility operation in Canada, as well as other gas distribution businesses, CustomerWorks, gas services businesses, Aux Sable and wind power businesses; and
- International, which includes the Company's two energy-delivery investments outside of North America.

Organic Growth Projects

A key focus of the Company's strategy is growth through internally developed organic projects. The Company is targeting organic growth rates averaging 6% over the next five years. The Company is advancing the development of a number of organic growth projects, some of which are summarized below. Enbridge will continue to pursue acquisitions that are accretive to earnings, on an opportunistic basis, as a supplementary source of growth.

Project	Estimated Capital Cost (Canadian dollars unless otherwise noted)	Potential Date of Completion
Liquids Pipelines		
Spearhead Pipeline	US$190 million	March 2006
Surmont Laterals and Facilities	$42 million	Mid-2006
Athabasca Pipeline Expansions	$75 million	Mid-2006
Long Lake Laterals and Facilities	$45 million	Late 2006
Stonefell Terminal	$80 million	Late 2007
Upstream Terminaling	$460 million	2007
Downstream Terminaling	US$220 million	2007
Waupisoo Oil Pipeline	$400 million[1]	Mid-2008
Waupisoo Diluent Pipeline	$200 million[1]	Mid-2008
Southern Access Expansion — Canadian portion	US$135 million[1]	2009
Southern Access Extension	US$250 - US$320 million[1]	2009
Gateway Condensate Import Pipeline	$1,700 million[1]	2010
Gateway Petroleum Export Pipeline	$2,500 million[1]	2010
Alberta Clipper Pipeline — Canadian Portion	US$1,020 million[1]	2010
Sponsored Investments (EEP)		
Project Clarity — East Texas	US$530 million	2007
Southern Access Expansion — U.S. portion	US$815 - US$980 million[1]	2009
Alberta Clipper Pipeline — U.S. Portion	US$570 million[1]	2010
Cushing Terminal Expansion	US$55 million	2006
Gas Pipelines		
Neptune Laterals	US$125 million	End of 2007
Gas Distribution and Services		
EGD Customer Additions & System Integrity	$1,500 million	2006-2010
Ontario Wind Project	$400 million	Early 2007
Rabaska LNG Facility	$280 million by Enbridge	2010

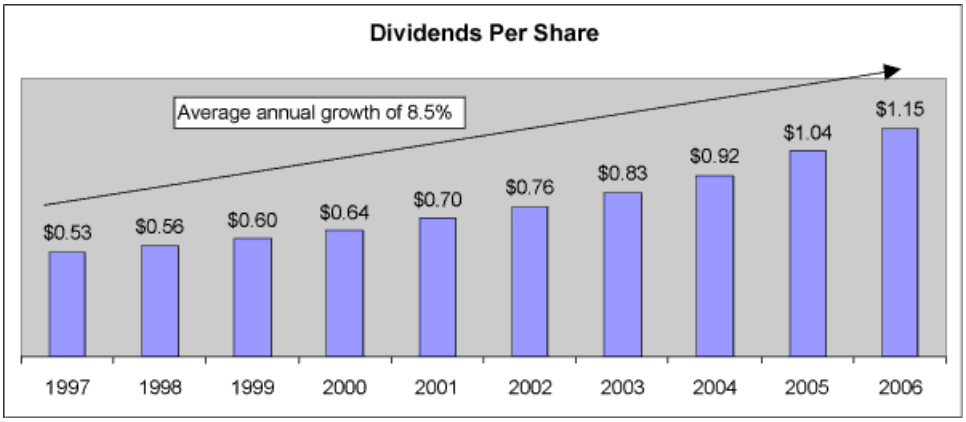
[1] Estimated capital costs for these projects are reported in 2005 dollars and exclude escalation to the year of expenditure.

There are a number of competing projects, proposed by other companies, which could preclude the Company from developing one or more of these proposed projects.

Descriptions of each project are included in the strategy section of each core business.

Dividends

The Company has modified its dividend payout ratio to reflect a strong long-term outlook for the business, shareholders' increasing preference for income and a challenging acquisition market, which will create surplus capital in the near term. Starting in the fourth quarter of 2005, the Company is targeting to pay out approximately 60% to 70% of earnings as dividends, an increase from the previous target of 50% to 60% of earnings. The following chart shows dividends per share for the last 9 years and annualized pro-forma dividends for 2006, assuming the Board does not increase the dividend subsequent to the increase announced in November 2005.



Strategy

Enbridge has four key strategies to achieve the overall objective of generating long-term value for shareholders.

1. Expand Existing Core Asset Platforms

The Company will expand its core asset base and existing businesses. Strategies for each core business are included in the sections below.

2. Develop New Growth Platforms

Enbridge believes it is also important to develop new growth platforms that complement the existing core asset base in the following areas:

- Liquefied Natural Gas (LNG) Regasification — Develop LNG regasification projects and related pipeline infrastructure, concentrating on projects that leverage the existing downstream asset base.
- Marketing and Storage — Pursue marketing and storage opportunities to optimize existing assets and stimulate growth initiatives for both oil and gas pipelines.
- Power Generation — Continue to explore gas-fired power generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. Also, increase the scale of the wind power business and build in locations near existing Enbridge infrastructure.
- New Energy Technologies — Support development of new technologies that are near commercialization and complement existing businesses. Initiatives will focus on

technologies that enhance the economics of oil sands development and thereby ultimately enhance the value of the liquids transportation franchise.

3. Capitalize on the Partnership/Trust Model

Enbridge owns investments in EIF and EEP, which will develop or acquire energy infrastructure assets in North America and optimize the returns on assets they currently own.

4. Focus on Operational Excellence

Enbridge will continue its focus on operational excellence, including cost efficiency, safety and reliability, customer relationships, environmental integrity, innovation and effective stakeholder relations.

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

Corporate Social Responsibility

Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical manner, protecting the environment and health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures with which the Company works. CSR covers the Company's involvement in areas such as the environment, safety, corporate governance, community investment and stakeholder engagement.

Environmental initiatives include pursuing alternative and renewable energy technologies such as wind power, preventing pipeline leaks by conducting on-going maintenance programs as part of the comprehensive integrity management of pipelines and facilities, and the development of a carbon management strategy to manage the risks from green house gas emissions, such as methane. For example, replacing cast iron pipe with polyethylene mains at EGD is a key factor in reducing fugitive methane emissions. Safety initiatives include regular training and open communication with employees, emphasizing the importance of addressing health and safety risks before serious incidents occur and the establishment of local and regional environmental health and safety committees.

Corporate governance initiatives ensure a comprehensive system of stewardship and accountability is in place and functioning among directors, management and employees. For example, every employee and director must follow Enbridge's Statement on Business Conduct. Community investment initiatives include funding for the arts and health services, organizing local United Way campaigns and creating innovative partnerships with not for profit groups.

Stakeholder engagement means developing positive relationships with employees, suppliers, customers, investors, government agencies, environmental groups, business partners and local communities. Initiatives include early-stage project consultation on organic growth projects; public awareness programs on pipeline safety and regular customer surveys at EGD to better understand customer needs.

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.

LIQUIDS PIPELINES

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge System	**170.1**	171.6	162.0
Athabasca System	**48.6**	42.8	44.8
NW System	**7.3**	7.8	8.3
Saskatchewan System	**—**	—	3.1
Feeder Pipelines and Other	**3.1**	(2.3)	(4.7)
	229.1	219.9	213.5

Business Activities

Liquids Pipelines consists of crude oil, natural gas liquids and refined products pipelines, primarily in Canada.

Enbridge System

The mainline system is comprised of the Enbridge System and the Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). The system transports crude oil from Western Canada to the Midwest region of the United States and Eastern Canada and serves all of the major refining centers in Ontario. Enbridge has operated, and frequently expanded, the mainline system since 1949.

Tolls on the Enbridge System are governed by various agreements, which are subject to the approval of the National Energy Board (NEB). Significant agreements include the Incentive Tolling Settlement (ITS) applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement relating to the Terrace Expansion Project completed on April 1, 2003 which added additional capacity of 350,000 barrels per day and the System Expansion Program (SEP) II Risk Sharing Agreement related to SEP II, a 100,000 bpd expansion completed in 1998. Tolls on the older Mainline System have been governed by incentive tolling settlements since 1995. With the incentive tolling model, Enbridge and shippers share the benefits of cost reductions below agreed levels and the benefits of improvements in reliability and the quality of service. This approach aligns the Company's interests with those of its shippers.

Since Enbridge introduced incentive tolling arrangements in 1995, through the cost performance sharing mechanism of the ITS, after-tax benefits of $119.2 million have been shared by Enbridge and its customers, approximately 53% and 47%, respectively. Customers also realized an additional cumulative after-tax benefit of $16.2 million through the power guarantee mechanism of the ITS.

In 2005, Enbridge and the Canadian Association of Petroleum Producers (CAPP) approved the key terms of a new negotiated ITS, effective for January 1, 2005 to December 31, 2009. In January 2006, the NEB approved the new ITS. The new ITS continues the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In conjunction with the Terrace Agreement, the new ITS continues the throughput protection

provisions ensuring the Company is insulated from negative volume fluctuations beyond its control. In addition to the incentive-based provisions in prior agreements, service and reliability metrics, collectively performance metrics, have been added to the new ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets under the new performance metric provisions.

The service metrics establish financial bonuses and penalties for prescribed performance targets related to crude oil quality management and predictability of scheduled deliveries. The bonuses and penalties for the service metrics are limited to a maximum of $10 million after tax in 2005, escalating to $15 million in each of 2006 and 2007, and to $20 million in each of 2008 and 2009. The targets to achieve the maximum bonus under the ITS become increasingly difficult to achieve in successive years.

The reliability metric provides for bonuses and penalties associated with optimization of system capacity, which are calculated relative to annual capacity targets. If the Company's performance is below the target, it is charged a penalty of $200,000 after tax per percentage point for each month that performance is below the target. If the Company's performance exceeds the target, it earns $500,000 per percentage point for each month that performance is above the target. Practical constraints around pipeline capacity would limit the bonus for the reliability metric to approximately $12 million per year and penalties are limited to $10 million per year.

Athabasca System

The Athabasca System, a 540-kilometre (340-mile) synthetic and heavy oil pipeline, links the Athabasca oil sands deposits in the Fort McMurray, Alberta region, to a pipeline transportation hub at Hardisty, Alberta. The Athabasca System also includes the MacKay River and Christina Lake feeder lines and tankage facilities, as well as the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil storage services.

The Company has a long-term (30 year) take or pay contract with the major shipper on the Athabasca System, 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 ensures that the revenue recognized each period is in accordance with the underpinning return. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

NW System and Others

Enbridge's NW System is an 870-kilometre (540-mile) pipeline that transports crude oil from Norman Wells, in the Northwest Territories to Zama, Alberta. Earnings are based on an agreement with the primary shipper and are a product of a deemed common equity ratio of 55% (reduced to 50% after 2009) and the NEB multi-pipeline rate of return on common equity, plus any incentive cost savings.

Feeder Pipelines and Other primarily includes a number of liquids pipelines in the United States (Frontier, Toledo, Mustang, Chicap and Spearhead), as well as business development costs related to Liquids Pipelines activities.

Results of Operations

Liquids Pipelines earnings are $229.1 million in 2005 compared with $219.9 million in 2004. The increase is due to higher Athabasca System earnings, consistent with the take or pay agreement with the major shipper, and improved earnings from Feeder Pipelines and Other, primarily Frontier Pipeline, which paid Federal Energy Regulatory Commission (FERC) ordered reparations in 2004 and 2003.

Earnings from Liquids Pipelines were $219.9 million for the year ended December 31, 2004, an increase of $6.4 million from 2003. The increase resulted from higher earnings from the Enbridge System, which included incremental earnings from Terrace Phase III. The Saskatchewan System was sold to Enbridge Income Fund effective June 30, 2003.

Enbridge System

Enbridge System earnings are $170.1 million for the year ended December 31, 2005 compared with $171.6 million for the year ended December 31, 2004. The $1.5 million decrease is due to a lower earnings base from the ITS component of the Enbridge System, recently negotiated with the CAPP and approved by the NEB. As well, earnings were negatively impacted by higher taxes within the Terrace component. The decrease has been partially offset with earnings from the service and reliability incentives under the ITS as well as savings from cost management programs.

Enbridge System earnings are higher in 2004 than 2003 as they include incremental earnings from the Terrace Phase III expansion placed into service on April 1, 2003, as well as the increase in Enbridge's share of the Terrace surcharge. This increase is partially offset by a higher oil loss expense and a higher power allowance credit in 2004.

Athabasca System

Earnings for the year ended December 31, 2005 are $48.6 million, an increase of $5.8 million from 2004. The increase is consistent with the overall return underpinning the long-term take or pay contract with its major shipper as well as lower operating costs due to leak remediation in the prior year.

The Athabasca System 2004 earnings were $42.8 million for the year ended December 31, 2004 compared with $44.8 million for the year ended December 31, 2003. Earnings in 2004 included the contribution from the Hardisty storage caverns, completed in the fourth quarter of 2003. This was more than offset by higher tax expense as 2003 included the utilization of loss carryforwards.

NW System

Earnings in the last three years from the NW System have been consistent and reflect the effect of a declining rate base.

Feeder Pipelines and Other

Earnings in Feeder Pipelines and Other are $3.1 million for the year ended December 31, 2005 compared with a loss of $2.3 million for the year ended December 31, 2004. The increase is the result of Gateway condensate pipeline costs being deferred in 2005 whereas in 2004 they were expensed. In addition, Frontier Pipeline earnings were higher due to lower operating costs and the prior year included FERC ordered reparations.

Feeder Pipelines and Other earnings for the year ended December 31, 2004 increased $2.4 million from 2003 as a result of the Frontier reparations, the majority of which were recorded in 2003.

Strategy

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. The Liquids Pipelines strategy focuses on meeting the needs of Western Canadian producers. This can be achieved by reducing customers' costs, enhancing their access to premium markets and avoiding restrictions on production volumes caused by limited pipeline capacity.

On existing infrastructure, the Company will maximize cost efficiencies, ensure capacity is reliable and available when required and protect the quality and distinctiveness of the many different batches transported. The new ITS, described above, includes performance metrics which will reward the Company for achieving these goals and penalize the Company if performance in the prescribed areas falls below target levels.

The Company intends to enhance customers' access to favourable markets through ensuring that new transportation and storage infrastructure is developed on a timely basis, to meet customers' needs for expanded capacity in traditional markets and access to new markets with favourable pricing characteristics. There are many organic growth projects underway, described below, driven primarily by forecast increased production from the oil sands. Enbridge will only proceed with projects supported by shippers.

The Liquids Pipelines strategy will focus on: (i) continuing to develop regional Alberta oil sands infrastructure; (ii) enhance producer access to diluent, which is needed to dilute heavy oils so they can be transported through pipelines; (iii) increasing traditional core PADD II (U.S. Midwest) market penetration; (iv) pursuing new market access initiatives; and (v) continuing to develop customer and stakeholder relationships.

Supply and Reserves

The vast resource of the Western Canadian Sedimentary Basin (WCSB) and its development, create the basis for the Company's growth strategy. Generally, development of the oil sands resource has more than offset declining conventional production. In 2005, due to events such as the Suncor fire, growth in oil sands production did not offset the decline in production from conventional resources. The NEB estimates that total Western Canada 2005 production will be 2.3 million bpd[1] at the end of 2005 (2004 — 2.2 million bpd). At the end of 2004, remaining established conventional oil reserves in Western Canada were estimated to be 3.8 billion barrels[2] and remaining established reserves from oil sands were estimated at 174 billion barrels[3]. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 14% of the worldwide estimated proven reserves[4].

(1) National Energy Board 2005 Estimate Production of Canadian Crude Oil and Equivalent Table 1

(2) Canadian Association of Petroleum Producers Statistical Handbook 2005

(3) Alberta Energy and Utilities Board Alberta's Reserves 2004 and Supply/Demand Outlook

(4) Oil and Gas Journal's Worldwide Look at Reserves and Production, December 19, 2005

Demand for WCSB Crude

The Company's liquids pipelines are dependent upon the demand for crude oil and other liquid hydrocarbons produced from Western Canada. Historically, the pipeline system has delivered crude oil to two main markets: Ontario/Quebec, and the Midwest portion of the United States

with some volume delivered to Western Canada. Through Company initiatives, crude oil will begin to penetrate southern markets in PADD II with the Spearhead Pipeline as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.

Historically, Canada has been the third largest supplier of crude to the U.S. However, for the past two years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. Western Canada demand is served by local supply and has increased by 25,800 bpd over the last two years. During 2005, an equal mix of Western Canadian and Atlantic Basin crude satisfied Ontario's crude oil requirement. Deliveries to Ontario from Western Canada and from Montréal, Quebec declined in 2005 with the closure of Petro-Canada's Oakville refinery. Deliveries of WCSB crude into PADD II (the U.S. Midwest) remained relatively flat over the last two years with reduced WCSB crude oil supply in 2005. U.S. deliveries of Canadian crude demonstrated a growth of 116,400 bpd by December compared to Q3 2005, as Suncor's recovered production entered the market. Over the same two-year period, deliveries into PADD IV (the U.S. Rocky Mountains) have increased by 30,800 bpd and PADD V (the Western U.S.) deliveries have increased by 25,000 bpd.

The abundance of established reserves from oil sands, the proximity to the U.S. markets and the relative geopolitical attractiveness of the resource, as well as strong demand, will provide opportunities for the expansion of Enbridge's Athabasca System and the Enbridge System as well as the development of new pipelines.

Alberta Oil Sands Infrastructure

A number of projects are underway to develop oil sands infrastructure including the Gateway, Waupisoo, Surmont and Long Lake projects, described below. Both the Gateway and Waupisoo projects provide for diluent pipelines that would bring needed diluent to the oil sands resource.

The Gateway Project

The Gateway Project, which includes both a condensate import pipeline and a petroleum export pipeline, continues to progress through the commercial development phase needed to achieve sufficient shipper commitments for each line. Originally, a 16-inch condensate import pipeline was planned at an expected cost of approximately $1.7 billion on a stand-alone basis. Based on the results of the Open Season, Enbridge expects to increase the diameter of the pipeline from 16 inches to 20 inches. Enbridge has also offered condensate line shippers the option to participate, as partners, in the ownership of the pipeline. Final commitment amounts and transportation agreements, as well as ownership agreements, are nearing the final stages of negotiations. At the same time, updated cost estimates are being prepared for each line. The estimates, along with the respective tolls, will be required prior to execution of shipper agreements for both pipelines.

The petroleum export line, which would transport crude oil from the Edmonton area to the Canadian west coast, closed its open season in December 2005 and discussions with interested shippers have commenced with the objective of signing final agreements by the second quarter of 2006, in time for the anticipated regulatory filing. As with the condensate line, interest expressed during the open season supports an increase of the pipeline diameter from 30 inches to 36 inches. The petroleum export pipeline is expected to cost approximately $2.5 billion (in 2005 dollars) on a stand-alone basis and, if both parts of the Project proceed together, total savings of approximately $550 million could be realized.

The decision to proceed with the regulatory filing for either pipeline is subject to commercial considerations, including satisfactory completion of shipper agreements, environmental assessment as well as public and Aboriginal consultation. If the Project proceeds, construction could begin as early as 2008 with a target in-service date early in 2010.

Waupisoo Pipeline Project

During the third quarter of 2005, Enbridge reached agreements with shippers on long-term transportation commitments on the proposed Waupisoo Pipeline. The 30-inch diameter, 380-kilometer long pipeline will transport crude oil from the Cheecham terminal, currently under construction on the Athabasca Pipeline, to the Edmonton, Alberta area. The initial capacity of the line will be 350,000 bpd and is expandable to a maximum of 600,000 bpd through the addition of pumping units. Enbridge has filed an application for regulatory approval with the Alberta Energy and Utilities Board and other provincial government departments. Pending regulatory approvals, expected in mid-2006, Enbridge will begin construction on the approximately $400 million pipeline in 2007, with an expected in-service date of mid-2008.

Based on interest expressed by oil sands producers, Enbridge is including a 16-inch, 150,000 bpd diluent return line from the Edmonton area refinery hub north to the oil sands within the scope of the project for regulatory approval and public consultation. The diluent line is expected to cost approximately $200 million. Shipping commitments on the diluent line have not been finalized.

Surmont Oil Sands Project

Enbridge entered into final agreements with ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. (the Surmont Shippers), to provide pipeline transportation services on the Athabasca Pipeline starting in mid-2006. Enbridge will construct the pipeline and tank facilities required by the Surmont Project at the Cheecham terminal on the Athabasca Pipeline. The estimated cost of these facilities is $42 million. The agreements provide for an initial contract volume of up to 50,000 bpd of crude oil with the option to increase the contract volume to up to 220,000 bpd for future phases of production. The agreement covering the dedicated Surmont lateral facilities and the agreement for transportation service on the Athabasca Pipeline are both for an initial term of 25 years, with extension provisions. The Athabasca Pipeline agreement also provides flexibility for the Surmont Shippers to transfer their production to the proposed Waupisoo Pipeline to the Edmonton area.

Long Lake Oil Sands Project

During the first quarter of 2005, the Company finalized agreements with Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) to provide pipeline transportation services for the Long Lake Project.

Under the terms of the agreements, Enbridge will construct, own and operate the pipeline and tank facilities required by the Long Lake Project, as well as pipeline laterals and tank facilities at the Cheecham terminal on the Athabasca Pipeline. The estimated cost of these facilities is $45 million with a planned in-service date in late 2006. Enbridge's 545 kilometer Athabasca Pipeline will also require capacity expansion from the Cheecham terminal to its mainline terminal at Hardisty, Alberta.

The agreements provide for an initial contract volume of up to 60,000 bpd of crude oil with provisions for volume increases. The agreement covering the Long Lake lateral facilities is for a term of 25 years and the agreement for service on the Athabasca Pipeline is for a 50-month term with extension provisions.

Athabasca Pipeline Expansions

In 2005, the Company initiated several expansion projects on the Athabasca Pipeline. The expansion projects include the addition of two pumping stations, one at Elk Point and one at Cheecham, as well as modifications to existing pumping stations. In addition, the Company is adding three new tanks at the Athabasca Terminal. The projects are scheduled to be completed in mid-2006 at a total cost of approximately $75 million.

Market Penetration and Access

Three projects currently under consideration which would increase PADD II penetration and would provide improved access to North American markets are the Southern Access Project, which would expand and extend the mainline, the Alberta Clipper Pipeline, the next tranche of mainline capacity, and the Spearhead Pipeline reversal project, which will provide access for Canadian crude to the Cushing refinery hub.

Southern Access Mainline Expansion and Extension Program

On December 23, 2005, EEP, Enbridge's 10.9%-owned affiliate, filed a tolling application with the FERC with respect to the 400,000 bpd Southern Access expansion from the Canada/U.S. border to Griffith, Indiana. The FERC filing is endorsed by CAPP and a FERC decision is expected in the first quarter of 2006. The cost of the expansion is estimated at approximately US$815 million to EEP. The program is scheduled to be brought into service in stages, with 44,000 bpd in 2007, an additional 146,000 bpd in 2008 and the final 210,000 bpd in 2009. CAPP may request a delay of the target in-service dates if production growth is slower than forecast, but in such case EEP can recover any costs incurred to the date of notification.

Enbridge has also negotiated the Canadian expansion agreement with CAPP for the Southern Access Expansion between Hardisty, Alberta and the Canada/U.S. border. Enbridge intends to file for NEB approval of the Canadian expansion in 2006, the cost of which is estimated at US$135 million to Enbridge. The Canadian facilities can also be staged, and the in-service dates will be timed to coincide with the U.S. facilities.

Enbridge continues to discuss the extension of the mainline from Flanagan, IL to Patoka, IL or potentially Wood River, IL with shippers. The extension would involve the construction of a new 30-inch diameter, 300,000 bpd pipeline, at a cost of approximately US$250 million to US$320 million to Enbridge.

Alberta Clipper Pipeline

Enbridge anticipates that additional capacity to the U.S. Midwest, over and above Southern Access, described above, will be required. The Company has been actively developing the next tranche of mainline expansion capacity, the Alberta Clipper Pipeline, with selected shippers. The Alberta Clipper Pipeline project involves a new 36" line from Hardisty, Alberta to Superior, Wisconsin where it will interconnect with the existing mainline system to provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing. The line would involve a total investment of US$1.6 billion (in 2005 dollars) for an initial capacity of 400,000 bpd. Shipper interest to date has been strong, and the Company will expand these discussions during the first quarter of 2006 to seek broad industry support.

Spearhead Pipeline

Enbridge acquired 90% of the Spearhead Pipeline in 2003 and the remaining 10% in 2005. The Company is reversing the flow of the pipeline, which previously operated from Cushing to

Chicago, to bring crude oil from Chicago to Cushing. The Spearhead Pipeline project is currently estimated to result in a total investment of $230 million, of which approximately $220 million has been spent. The reversed pipeline is expected to be in service in March 2006.

Other Projects

Contract Terminaling

Enbridge directly, and through EEP, has developed a significant position in the contract terminaling business in recent years, with a total of 12 million barrels of storage capacity at six Canadian and U.S. locations. With increasing crude oil production and price volatility, the Company is encountering strong demand from producers, refiners and marketers for term storage capacity and associated terminaling services. In addition to the $80 million Stonefell terminal agreement for the BA Energy Upgrader, described below, the Company has numerous other terminaling investment opportunities, aggregating approximately $460 million in Canada and US$220 million in the U.S., either secured or well advanced.

Stonefell Terminal

BA Energy Inc. is building a bitumen upgrader near Fort Saskatchewan, Alberta for which Enbridge has agreed to provide pipeline and terminaling services. Based on initial scope and cost estimates, Enbridge expects to invest approximately $80 million in new facilities to provide storage services at a new satellite terminal it will develop adjacent to the upgrader. Enbridge will also provide pipeline transportation for the upgrader's output from the new terminal to a refinery hub near Edmonton. These facilities are expected to be in service in the fourth quarter of 2007.

Olympic Pipe Line

In December 2005, Enbridge announced that it will acquire a 65% interest in the Olympic Pipe Line Company (Olympic) from BP for US$99.8 million, subject to working capital adjustments. The transaction closed on February 1, 2006. Olympic owns 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 480 kilometers (400 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland and consists of 640 kilometers (300 miles) of 6-to-20 inch diameter pipe, a 500,000-barrel products terminal, 9 pumping stations and 21 delivery points or facilities. Olympic is the sole supplier of jet fuel to the Seattle-Tacoma International Airport and is a major supplier to the Portland International Airport. BP will continue to operate the pipeline system.

Customer and Stakeholder Relationships

To meet the Company's objective of continuing to develop customer and stakeholder relationships, Liquids Pipelines will focus on achieving operational excellence including assuring best practices relative to system reliability, safety, environmental issues and cost efficiency. The Liquids Pipelines business will continue its efforts to maintain a high level of customer satisfaction while striving to meet performance metrics targets in the new ITS.

Capital Expenditures

Liquids Pipelines generally spends $80 to $100 million each year on ongoing capital improvements and core maintenance capital projects. This trend is expected to continue in 2006. Expenditures for organic growth projects described above are expected to be approximately $230 million during 2006 in Canada.

Legal Proceeding — CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced an action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. The Plaintiffs have filed a motion to establish a cause of action, one of the requirements to have the motion certified as a class action under the *Class Proceedings Act* (Ontario). These matters are currently before the Ontario District Court for hearing. Since the outcome is indeterminable, the Company has made no provision for any potential liability.

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 are dependent upon the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, is dependent upon a number of variables, including the availability and cost of capital and labour for oil sands projects, the price of natural gas used for steam production, and the price of crude oil. Demand is dependent, among other things, on weather, gasoline consumption, manufacturing, alternative energy sources and global supply disruptions.

Performance Metrics

The new 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 new ITS, for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $25 million in 2006 and 2007 and $30 million in 2008 and 2009.

Regulation

Earnings from 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 these operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity. For 2006, this rate of return is 8.88%. 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 can be reduced through the negotiation of long-term agreements with shippers.

Competition

Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, and proximity to markets. Other common carriers are available to producers to ship Western Canadian crude oil to refineries in either Canada or the United States. Although the Company does not compete directly in the regions served by these other pipelines, producers can elect to have their crude oil refined at delivery points not on the Enbridge System. 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. Also, 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 and is exposed to volume fluctuations.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines. Available capacity on the Athabasca System is expected to be more competitive than a new pipeline.

Competition also impacts the Company's ability to execute organic growth projects as a number of competing projects, proposed by other companies, could preclude the Company from developing one or more of the proposed projects. The Company also anticipates challenges in securing the labour that would be required to complete the projects.

GAS PIPELINES

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Alliance Pipeline US	**32.1**	37.4	40.3
Vector Pipeline	**15.9**	16.4	10.2
Enbridge Offshore Pipelines	**11.8**	—	—
Alliance Pipeline Canada	**—**	—	19.6
	59.8	53.8	70.1

Business Activities

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 the US portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising the Enbridge Offshore Pipelines. Alliance Pipeline Canada was sold to EIF effective June 30, 2003. EIF is included in Sponsored Investments below.

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 700-kilometre (440-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois and has the capacity to deliver 1.55 billion cubic feet per day (bcf/d).

Alliance has take-or-pay contracts ending in 2015 to transport 1.325 bcf/d of natural gas. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, cost of financing, an allowance for income tax, an annual allowance for depreciation, and an allowed return on equity. Each contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. The rates and tariff for Alliance Pipeline US are regulated by the FERC in the United States.

Alliance connects with a natural gas liquids (NGL) extraction facility (Aux Sable) 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. Aux Sable is owned 42.7% by Enbridge and its results are included under Gas Distribution and Services.

Vector Pipeline

The Company provides operating services to, and holds a 60% investment in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.0 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 70% 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 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.

In 2005, Vector Pipeline announced plans to construct two additional compressor stations, which would expand Vector Pipeline's capacity from 1 bcf/d to 1.2 bcf/d. Vector Pipeline has negotiated long-term binding agreements with shippers and initiated the filing process with the FERC. Preliminary engineering and environmental work is underway and the expansion is expected to be in service by the fourth quarter of 2007.

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines (EOP) 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. The operations were purchased December 31, 2004. These pipelines include almost 2,400 kilometers (1,500 miles) of underwater pipe and onshore facilities and transport more than half of all current deepwater Gulf of Mexico natural gas production. These pipelines normally transport approximately 2.7 billion cubic feet per day (bcf/d).

The primary shippers on the EOP systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, EOP provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the maximum sustainable production that is achievable.

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.

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

Results of Operations

Earnings from Gas Pipelines are $59.8 million for the year ended December 31, 2005, an increase of $6.0 million from 2004. The increase in 2005 is due to incremental earnings from Enbridge Offshore Pipelines, acquired on December 31, 2004.

Earnings from Gas Pipelines were $53.8 million for the year ended December 31, 2004, a decrease of $16.3 million from 2003 related primarily to the disposal of Alliance Pipeline Canada to EIF on June 30, 2003.

Alliance Pipeline US

Alliance Pipeline US earnings are $32.1 million for the year ended December 31, 2005 compared with $37.4 million for the year ended December 31, 2004. The moderate decrease is due to the stronger Canadian dollar in 2005.

Alliance Pipeline US earnings for the year ended December 31, 2004 were $2.9 million lower than earnings for the year ended December 31, 2003. The decrease reflected the impact of the stronger Canadian dollar in 2004 compared with 2003, and the favourable impact, in 2003, of the adjustment recorded in Alliance to reflect a higher rate base.

Vector Pipeline

Vector Pipeline earnings are $0.5 million lower for the year ended December 31, 2005 compared with the year ended December 31, 2004 resulting from the stronger Canadian dollar in 2005.

Earnings from Vector Pipeline were $6.2 million more in 2004 compared with 2003, as a result of increased volumes and transportation margins, additional ownership interest of 15.0% acquired in the fourth quarter of 2003 and Canadian dollar effects.

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines, acquired on December 31, 2004, contributed $11.8 million to earnings in 2005. Hurricanes Katrina and Rita negatively affected transmission volumes and the results of this business. The results include property insurance deductibles as well as lost revenue on various systems prior to the commencement of contingent business interruption insurance coverage. The combined effect of the property damage deductibles and the estimated lost revenue reduced expected earnings by approximately $15 million. In 2006, earnings will likely also be affected, although to a much lesser degree.

As of December 31, 2005, the pipelines were transporting 90% of pre-hurricane volumes, or approximately 2.4 bcf/d, compared with the pre-hurricane rate of approximately 2.7 bcf/d. The impact on each corridor is described below.

The Mississippi Canyon Corridor was in the direct path of Hurricane Katrina. Minor damage to the Enbridge facilities was isolated primarily to onshore electrical, control and measurement equipment. Two key production source platforms and the Venice gas processing plant, all owned by others, were damaged. Between early September and mid-November 2005, no volumes moved through the Mississippi Canyon Corridor. By year-end, approximately 0.43 bcf/d or 75% of the pre-Katrina throughput level was back on line. Repairs to upstream and downstream infrastructure should allow throughput to fully recover in 2006.

Hurricane Katrina caused modest damage to certain Enbridge assets in the Destin Corridor. However, upstream and downstream oil and natural gas liquids pipelines facilities owned by others experienced damage and were not operational until mid-October. Operations were restored by the end of October with production throughput continuing to increase as repairs of non-Enbridge facilities were completed. As of December 31, 2005, volumes on the Destin Corridor were up to 0.89 bcf/d which is approximately 95% of the pre-hurricane level.

Hurricane Rita caused no material incremental damage to the Mississippi Canyon and Destin Corridors.

Hurricanes Katrina and Rita caused no material damage in the Green Canyon Corridor and volumes were unaffected by the hurricanes.

The Garden Banks and Stingray Corridors were in the direct path of Hurricane Rita. In these corridors, there was minimal damage to the Enbridge owned offshore pipelines and platform facilities. In the Garden Banks Corridor, volumes returned to pre-hurricane levels in mid-November when repairs to an upstream producer gathering line were completed. Volumes on the Stingray pipeline began flowing again in early November at a rate of approximately 0.1 bcf/d and were at 0.325 bcf/d by year-end or 65% of pre-hurricane levels. Volumes are expected to return to pre-hurricane levels in early 2006 following completion of repairs to the Stingray onshore plant facility scheduled for January, 2006 and repairs to third party processing facilities.

Strategy

The five main elements of the Gas Pipelines strategy are: (i) continue to expand the existing Alliance and Vector systems and position them for northern gas development; (ii) capitalize on the offshore Gulf of Mexico assets through continued joint venture consolidation, connection of new gas discoveries and acquisition of other deepwater systems; (iii) consolidate Enbridge's assets in the Chicago-to-Dawn corridor and extend its presence downstream of Dawn; (iv) achieve an equity participation in an Alaska-to-Alberta gas pipeline in partnership with producers; and (v) pursue and develop pipeline infrastructure required to move U.S. Rockies gas to the Midwest and northeastern markets. The strategy is based on the Company's assessment of the supply and demand for natural gas.

Supply and Demand for Natural Gas

North American natural gas demand is expected to grow at a modest rate for the next three to five years primarily driven by growth in power generation, which more than offsets declines in industrial demand. The re-emergence of coal as a generation source, due to advances in clean-coal technology, as well as the re-emergence of nuclear power as a source of electricity generation will mitigate growth in the demand for natural gas in that sector. The development of oil sands projects in Alberta also impacts the demand for natural gas, as various extraction and upgrading processes require the use of natural gas. Demand growth is expected to be constrained by recent strong prices and increased volatility due to supply concerns from traditional sources. Over time, the entry of new supplies from the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as Liquefied Natural Gas are expected to alleviate supply concerns and provide opportunities for Enbridge to deliver this natural gas to markets.

To respond to this expected growth in demand, Enbridge will further develop its existing gas pipelines investments and pursue new growth platforms including an increased presence in the Gulf of Mexico. Offshore development is expected to include options that offer both crude oil and natural gas transportation. Alliance will focus on cost-effective optimization, more efficient maintenance practices and increased heating values. Alliance is well positioned to participate in the delivery of Alaska/Mackenzie Delta gas to markets in the United States. Vector's strategy will focus on ensuring a safe and cost-efficient expansion for a late-2007 in-service date. New growth platforms could include significant ownership in a pipeline transporting gas from the U.S. Rockies; ownership in a pipeline connecting Dawn, Ontario, to New York State; storage facilities in Ontario and a significant ownership position in other storage facilities; as well as the pursuit of an equity participation in the Alaska-to-Alberta gas pipeline.

The Company continues to pursue developments in the Gulf of Mexico, building on its initial $754 million investment in EOP. During 2005, Enbridge increased its interest in Garden Banks Gas Pipeline and Neptune Pipeline Company, two systems within EOP. The Company believes

that gas production from the deepwater Gulf of Mexico will increase from pre-Hurricane Katrina flows of 3.5 to 4.0 bcf/d to approximately 8 bcf/d by 2010. Strategically, the Company believes that its status as an independent operator, not a producer, will allow for the further consolidation of joint venture interests across the Gulf of Mexico. Further growth is anticipated from connecting new leases and entry into oil pipelines.

Neptune Project

The Company plans to construct and operate both a natural gas lateral and a crude oil lateral to connect the deepwater Neptune oil and gas field in the Green Canyon Corridor to existing Gulf of Mexico pipelines, extending Enbridge's existing Gulf of Mexico infrastructure. The laterals are expected to cost a total of approximately US$125 million and will have the capacity to deliver in excess of 200 mmcf/d and approximately 50,000 bpd of oil. Construction of the Neptune oil and gas laterals is scheduled for the second quarter of 2007 with first throughput expected by year-end 2007.

Capital Expenditures

The Company expects to spend approximately $100 million in 2006 in the Gas Pipelines segment for on ongoing capital improvements, core maintenance capital projects and expansion, including the Neptune Project described above.

Business Risks

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

Alliance Pipeline US and Vector Pipeline

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess supply environment mainly because of long-term capacity contracts going to 2015. Vector Pipeline 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 the shippers to perform their contractual obligations under the transportation contracts 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 agreed thresholds. Vector Pipeline also has a diverse group of long-term transportation shippers, which includes 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, with a combined transportation capacity of approximately 3.8 billion cubic feet per day (bcf/d) 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 delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US's 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 70% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts penalize early termination if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigation factors is evidenced by the increase in the utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US are regulated by the FERC which has the responsibility to ensure that rates charged are not greater than those necessary to enable the pipelines to recover costs prudently incurred and to earn a reasonable return. Under FERC regulations, the FERC, shippers and others have the opportunity to contest rates and the tariff structure.

Enbridge Offshore Pipelines

Weather

Adverse weather, such as hurricanes, may impact EOP financial performance directly or indirectly. Direct impacts may include damage to EOP 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 indirectly decrease throughput on EOP systems.

Competition

There is significant competition for new and existing business in the Gulf of Mexico. EOP has been able to capture key opportunities, which extends its footprint, positioning EOP to more fully utilize existing capacity. EOP serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has EOP 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. However, 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 EOP'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.

SPONSORED INVESTMENTS

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Income Fund (EIF)	**34.2**	30.0	17.6
Enbridge Energy Partners (EEP)	**21.7**	28.6	27.3
Gain on sale of assets to EIF	**—**	—	169.1
Dilution gains	**8.9**	7.6	20.3
	64.8	66.2	234.3

Business Activities

Sponsored Investments includes the Company's 10.9% ownership interest in EEP and a 41.9% equity 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.

Enbridge Energy Partners (EEP)

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 pipelines and a crude oil feeder pipeline in North Dakota.

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner, 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	Enbridge
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 2005, EEP paid quarterly distributions of $0.925 per unit (2004 — $0.925 per unit; 2003 - $0.925 per unit). Of the $21.7 million Enbridge recognized as earnings from EEP during 2005, 64.7% (2004 — 50%; 2003 — 49%) were incentive earnings while 35.3% (2004 — 50%; 2003 — 51%) were Enbridge's share of EEP's earnings.

Enbridge Income Fund (EIF)

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the Enbridge Saskatchewan System, both purchased from the Company in 2003. The Alliance Pipeline Canada, is the Canadian portion of the Alliance System, described in the Gas Pipelines segment above. 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 Inc.'s mainline pipeline to be transported to the United States.

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 2005, the Company received incentive fees of $2.1 million (2004 — $0.8 million, 2003 — nil). The Company is the primary beneficiary of EIF through a combination of the voting units and a preferred units investment and as such EIF is consolidated, starting January 1, 2005, under variable interest entity rules.

Results of Operations

Earnings from Sponsored Investments are $64.8 million for the year ended December 31, 2005 compared with $66.2 million in 2004. EIF has increased earnings of $4.2 million due to allowance oil sales on the Saskatchewan System and collection of a notional tax in tolls on Alliance Canada. This increase is more than offset by EEP's non-cash unrealized mark-to-market losses on derivative instruments that are considered ineffective hedges for accounting purposes.

The decrease in 2004 earnings compared with 2003 stems from the gain of $169.1 million on the sale of the Company's interests in Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) to EIF in 2003.

Enbridge Income Fund

EIF earnings are $34.2 million for the year ended December 31, 2005 compared with $30.0 million for the year ended December 31, 2004. The 2005 results include higher preferred unit distributions as well as higher incentive income consistent with EIF's cash distribution increases

in 2004. EIF's operating results benefited from strong performance at both Alliance Pipeline Canada and the Saskatchewan System.

Earnings for 2004 include a full year of operations whereas earnings for 2003 included only the six months from inception of EIF on June 30, 2003.

Enbridge Energy Partners

Earnings of $21.7 million for the year ended December 31, 2005 are down from 2004 earnings of $28.6 million due to $5.0 million (net to Enbridge) of unrealized mark-to-market losses on derivative financial instruments, which do not qualify for hedge accounting treatment. While Enbridge believes the hedging strategies are sound economic hedging techniques, they do not qualify for hedge accounting and must be accounted for on a mark-to-market basis through earnings. In addition, EEP earnings have been negatively affected by lower Lakehead System volumes, a stronger Canadian dollar and a lower ownership interest offset with higher earnings from the natural gas business.

EEP's 2004 results reflected higher operating earnings, compared with 2003, partially offset by the stronger Canadian dollar, a lower ownership interest and the negative effect of a FERC decision requiring a refund to shippers on one of EEP's regulated natural gas pipelines. The higher operating earnings were from increased volumes on the main crude oil liquids pipeline system, as well as increased throughput and higher processing margins on various natural gas assets.

EEP issued partnership unit in each of 2005, 2004 and 2003. Because Enbridge did not fully participate in these offerings, dilution gains resulted.

Strategy — EEP

EEP intends to grow primarily through organic growth, supplemented by opportunistic acquisitions. Specifically, EEP intends to:

- increase the utilization and productivity of its core assets to meet the supply of and demand for hydrocarbons in the markets EEP serves; and
- develop and acquire complementary energy delivery assets, particularly in the Gulf Coast region of the United States, and improve the financial performance and operating efficiency of these assets.

On January 30, 2006, EEP announced that it has received customer commitments to support the construction of a US$530 million expansion and extension of its East Texas natural gas system (Project Clarity). The Project will handle growing natural gas production in East Texas and will consist of a 36 inch intrastate pipeline with a capacity of approximately 700 mmcf/d, a 250 mmcf/d treating facility and a number of upstream facilities, including gathering pipelines all of which are expected to be fully operational in late 2007.

Strategy — EIF

Enbridge Income Fund will continue to position itself as a premier income fund in Canada with a value proposition characterized by a low risk profile with dependable but modest organic growth, long-life assets and potential for further growth through energy infrastructure acquisitions.

Business Risks

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

Enbridge Energy Partners

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 expects future increased crude oil supplies from the oil sands projects in Alberta. In addition, Enbridge's future plans to provide access to new markets in the southern United States are expected to increase demand for Western Canadian crude, resulting in increased volumes for EEP.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, natural gas liquids 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 FERC or state regulators and their 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 does business.

Market Price Risk

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

Enbridge Income Fund

Risks for Alliance Pipeline Canada are similar to those identified for the Alliance Pipeline US in the Gas Pipelines segment.

The majority of the volumes shipped on the Saskatchewan and Westspur common carrier pipeline systems, components of the Saskatchewan System, have 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. However, there is limited pipeline competition in this area. The main competition to the pipelines is from trucking.

EIF's liquids and natural gas pipelines are dependent upon the supply of and demand for crude oil and natural gas from Western Canada. Supply, in turn, is dependent upon a number of variables, including the level of exploration, drilling, reserves and production of crude oil and natural gas, the accessibility of Western Canadian crude oil and natural gas, the price and

quality of crude oil and natural gas available from alternative Canadian and United States sources. In addition, the regulatory environments in Canada and the United States, including the continued willingness of the governments of both countries to permit the export of crude oil and natural gas from Canada to the United States on a commercially acceptable basis, could impact the supply of crude oil and natural gas.

GAS DISTRIBUTION AND SERVICES

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Gas Distribution[1]	**111.9**	133.1	103.0
Noverco[1]	**28.3**	32.3	24.2
CustomerWorks/ECS	**23.2**	20.5	16.9
Other Gas Distribution[1]	**6.7**	8.5	6.8
Enbridge Gas New Brunswick	**6.1**	3.7	4.4
Gas Services	**0.2**	(2.8)	(5.9)
Aux Sable	**5.3**	7.3	(6.9)
AltaGas Income Trust (AltaGas)	**—**	21.1	12.3
Gain on sale of investment in AltaGas	**—**	97.8	—
Impairment loss on Calmar gas plant	**—**	(8.2)	—
Other	**(2.9)**	(0.2)	(1.2)
	178.8	313.1	153.6

[1] The year ended December 31, 2004 includes earnings for the 15 months ended December 31, 2004. The year ended December 31, 2003 includes earnings for the year ended September 30, 2003.

Business Activities

The largest portion of Gas Distribution and Services is the gas distribution operations of Enbridge Gas Distribution (EGD). This segment also includes Noverco, CustomerWorks, the gas services business, which manages the Company's merchant capacity commitments on Alliance and Vector, and the Company's investment in Aux Sable.

Enbridge Gas Distribution

EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.75 million customers in Central and Eastern Ontario, Southwestern Quebec, and parts of Northern New York State. EGD's operations in Ontario are regulated by the Ontario Energy Board (OEB).

Gas Distribution Rates

In November 2004, EGD received approval from the OEB for its 2005 rates, under a cost of service model. The key elements are summarized below:

Regulatory year	Requested 2006	Approved 2005	Approved 2003
Rate base (*millions of Canadian dollars*)	$ 3,596.2	$ 3,422.1	$ 3,155.8
Deemed common equity for regulatory purposes	35.00%	35.00%	35.00%
Rate of return on common equity	10.11%	9.57%	9.69%

The rate of return on common equity is calculated with reference to a formula approved by the OEB that incorporates the long bond yield forecast. The rate of return of 10.11% requested for 2006 was a preliminary calculation based on the forecast yield for long bonds used in the formula at the time the 2006 rate application was made. Subsequent movements in the forecast yield for long bonds have resulted in an updated rate of return on common equity of 8.74% becoming applicable for 2006.

EGD's 2005 and 2003 rates were established pursuant to a cost-of-service methodology that allowed revenues to be set to recover EGD's forecast costs. For 2004, rates were set by increasing 2003 rates by 90 percent of the forecast Ontario consumer price index, resulting in an increase of 1.8 percent. The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a weather-normalized basis exceed the benchmark ROE, these excess earnings were shared on a 50/50 basis between ratepayers and the Company's shareholders. The 2004 financial results for the fifteen months ended December 31, 2004 include a reduction of $8.7 million after tax for the earnings sharing with customers.

Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, 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 gas distribution, storage and transmission, as well as an allowance for working capital. Under the cost-of-service model, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs. EGD does not earn a profit on the price of natural gas.

The rate base is financed by EGD through a combination of debt and equity. The proportion of debt and equity, currently 65% and 35% respectively, is approved by the OEB. For the debt portion, interest expense incurred by the Company is recovered in rates. For the equity portion, the OEB sets the rate of return that EGD may recover in rates. The allowed rate of return on equity for EGD is based on the forecast yield on Canadian government long-term bonds.

Earnings from EGD are impacted to the extent that volumes sold differ from forecasted volumes. There are four key factors that affect the probability that EGD will distribute the forecast volumes. These are weather, economic conditions, gas prices and the prices of competing energy sources and the number of customers added. To the extent that these factors vary unfavourably compared with forecasts, earnings will be less than the total revenue requirements established in the ratemaking process due to lower distribution volumes.

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 annual average consumption.

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

2006 Rate Application

On March 18, 2005, EGD filed an application with the OEB for approval of the 2006 rates, under a cost-of-service model. A final decision on this rate application is expected from the OEB during the first quarter of 2006.

In 2005, EGD added approximately 50,700 customers (15 months ended December 31, 2004 — 74,500; 12 months ended October 31, 2003 — 54,800). The increased number of customers is

due primarily to the strong housing market in EGD's franchise area driven by low interest rates, urbanization and immigration patterns. EGD expects to continue to add 45,000 to 55,000 customers per year in the foreseeable future due to continued growth in the greater Toronto area. This level of customer growth would lead to continued growth of EGD's rate base. EGD serves approximately 95% of the residential homes in its franchise area and, as the price of natural gas continues to be favourable relative to competing energy sources, expects to continue this level of market penetration.

CustomerWorks/ECS

CustomerWorks/ECS includes the operations of CustomerWorks and Enbridge Commercial Services (ECS). CustomerWorks is 70% owned by Enbridge and provides customer care services, including billing, collections, and operation of call centers primarily for; EGD, Direct Energy Essential Home Services and Terasen (a gas distribution company in British Columbia). ECS owns the customer information services system that CustomerWorks uses under license to provide services to EGD.

Noverco

Enbridge owns an equity interest in Noverco through ownership of 32% of the common shares and a cost investment through ownership of preferred shares. Noverco is a holding company that owns approximately 75% of Gaz Metro Limited Partnership (Gaz Metro), a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro also has a 50% interest in TQM Pipeline, which transports natural gas in Quebec.

Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings adjustments at Enbridge. Noverco receives dividends from Enbridge but because Enbridge owns part of Noverco, a portion of the dividends Noverco receives are effectively dividends that Enbridge has paid to itself. This portion of the dividends paid reduces the book value of Enbridge's investment in Noverco.

Enbridge Gas New Brunswick

The Company owns 64% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 4,858 customers. Approximately 470 kilometers (294 miles) of distribution main has been installed with the capability of attaching approximately 20,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Aux Sable

Enbridge owns 42.7% of Aux Sable, a natural gas liquids (NGL) extraction and fractionation business. Aux Sable owns and operates a plant, attached to the terminus of the Alliance System. The plant extracts NGL 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 NGL, or lower heat content, and to take advantage of positive commodity price spreads. The NGL, which include ethane, propane, normal butane, iso-butane and natural gasoline, are resold. Aux Sable's ability to generate earnings is dependent on the difference between the prices of the NGL and natural gas, which Aux Sable must buy to replace the NGL it extracts from the Alliance System. Starting in 2004, heat content requirements were reduced providing increased operating flexibility, largely enabling Aux Sable to operate only when it is economic.

Aux Sable has entered into a binding memorandum of agreement with BP Products North America Inc. to sell all of its NGL production to BP at its facilities near Chicago. In return, BP will pay Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified thresholds. In addition, BP will compensate Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP will supply, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and will assume responsibility for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement will be for an initial term of 20 years, commencing December 31, 2005 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, however Aux Sable has the right to reduce such losses to avoid termination.

Gas Services

The Company's gas services business 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.

Tidal Energy

Tidal Energy (Tidal) provides crude oil marketing services for the Company and its customers in a full range of crude oil types including light sweet, light and medium sours and several heavy grades and natural gas liquids. Tidal 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's business involves buying, selling and storing large quantities of crude oil at low margins. Tidal does not trade on a speculative basis and its business is tightly monitored by, and must comply with, the Company's formal risk management policies. Earnings from Tidal are included in Other.

Results of Operations

Earnings are $178.8 million for the year ended December 31, 2005 compared with $313.1 million for the year ended December 31, 2004. The 2004 earnings include 15 months of operations from the gas distribution operations as a result of the change in EGD's fiscal year end. Also included in the earnings of 2004 is the after-tax gain of $97.8 million on the sale of the investment in AltaGas Income Trust.

Reported earnings for the year ended December 31, 2003 included EGD's results for the twelve months ended September 30, 2003.

Enbridge Gas Distribution

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Gas Distribution — as reported	**111.9**	133.1	103.0
Significant non-operating factors and variances:			
calendar year basis adjustment	**—**	(11.5)	0.8
regulatory disallowances	**—**	—	35.2
colder than normal weather	**—**	(21.3)	(33.9)
unbilled revenue	**—**	—	(33.6)
tax rate adjustments	**—**	—	51.4
	111.9	100.3	122.9

As noted above, earnings for the year ended December 31, 2004 included 15 months of earnings for Enbridge Gas Distribution, as a result of the elimination of the quarter lag basis of consolidation. Earnings for the first quarter, ended December 31, 2003, have been eliminated to adjust 2004 earnings to a calendar basis, making it comparable to 2005. The remaining EGD variance, after considering the items listed above, is the result of a higher rate base and a number of smaller positive variances across the utility.

Earnings for 2003 have also been adjusted to reflect the calendar basis, making them comparable with 2005. The 2003 regulatory disallowances related to gas costs for a long-term transportation contract, an outsourcing disallowance, as well as a $26.0 million write-down of a regulatory receivable. Unbilled revenue is the difference between amounts charged to customers based on estimated gas consumption and the actual volumes delivered in the reporting period. Starting October 1, 2003, EGD refined its process and began recording unbilled revenue on a quarterly basis using a current estimate of actual volumes delivered. In 2003, the unbilled revenue accrual was based on amounts approved by the OEB for the September 30 year-end. When the 2003 results are adjusted to reflect a calendar year, the quarter added, October 1 to December 31, 2003, has unbilled revenue recorded at the full December 31 amount. The quarter removed, October 1 to December 31, 2002, does not include the full impact of unbilled revenue because EGD was still using its previous estimation process during that period. Therefore, it is necessary to remove the effects of unbilled revenue, recorded in the quarter ended December 31, 2003, from the calendar adjustment to make 2003 comparable with 2004 and 2005.

Normal weather is the weather forecast by EGD in its annual rates application, in the Toronto area, including the impacts of both the long run and short run actual historical weather experience, more heavily weighted on the short run experience, and is subject to OEB approval. This financial measure is unique to EGD and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized factors that may be identified by other companies. Moreover, normal weather may not be comparable year-to-year given that the forecasting model weights the degree-days from the most recent years more heavily to determine the estimate. This weather-normalized adjustment method is the same as the manner in which EGD calculates degree-days for regulatory purposes.

Noverco

(millions of Canadian dollars)	**2005**	2004	2003
Noverco — as reported	**28.3**	32.3	24.2
Significant non-operating factors and variances:			
calendar year basis adjustment	**—**	(13.6)	3.4
dilution gains in Noverco on Gaz Metro issuances	**(7.3)**	—	(7.1)
tax rate adjustments	**—**	—	0.7
	21.0	18.7	21.2

Noverco earnings are $2.3 million higher for the year ended December 31, 2005 compared with the year ended December 31, 2004, after considering the items listed above. The increase reflects a future income tax recovery related to the receipt of cash dividends net of an adjustment for reciprocal dividends. During the year, the Company received a $70 million cash dividend from Noverco and recorded a $50 million adjustment for reciprocal dividends**.**

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%.

Other Gas Distribution Operations

(millions of Canadian dollars)	**2005**	2004	2003
Other Gas Distribution Operations — as reported	**6.7**	8.5	6.8
Significant non-operating factors and variances:			
calendar year basis adjustment	**—**	(2.1)	(0.4)
	6.7	6.4	6.4

Earnings from Other Gas Distribution Operations, after the calendar basis adjustment, are consistent for the three year period.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick earnings are $6.1 million for the year ended December 31, 2005 compared with $3.7 million for the year ended December 31, 2004. The increase is consistent with the settlement of debt through the issue of equity, resulting in a higher equity base.

Gas Services

Gas Services recorded earnings of $0.2 million for the year ended December 31, 2005, an improvement of $3.0 million from 2004. The Gas Services business includes several natural gas related businesses, including U.S. Oil acquired in January 2005.

Gas Services experienced a loss of $2.8 million for the year ended December 31, 2004, compared with a loss of $5.9 million in 2003. The improvement from 2003 reflected a continuing increase in the demand for natural gas and associated transmission services, reducing merchant capacity losses on the Alliance System and Vector Pipeline.

Aux Sable

Earnings for the year ended December 31, 2005 are $5.3 million compared with earnings of $7.3 million for the year ended December 31, 2004. The decrease is due to higher natural gas costs in 2005, which were not offset by product sales prices causing weak margins and therefore decreased production levels.

The positive earnings from Aux Sable in 2004 compared with 2003 were the result of positive fractionation margins. Enbridge's ownership interest in Aux Sable was also higher in 2004, as an additional 11.8% was acquired in April 2003 resulting in the current ownership of 42.7%. As the acquisition of the additional interest was at a discount to the book value, depreciation expense is lower on that additional interest.

AltaGas

The Company sold its investment in AltaGas in the third quarter of 2004. The earnings contribution from AltaGas in 2004 reflected a number of factors including an $8.0 million after-tax dilution gain.

Other includes higher costs in 2005, compared with 2004, related to the development of the Rabaska LNG facility.

Strategy

While EGD will continue to be under the cost-of-service model in 2006, EGD will continue to file through the cost-of-service process to ensure a just and reasonable base is in place for a 2008 incentive regulation plan. Enbridge will continue to explore new business opportunities that are complementary to the distribution business, including energy and fuel cell investments. Enbridge will pursue an industry facilitation strategy to make it easier for customers to find, install and finance natural gas appliances. Enbridge is committed to enhancing customer satisfaction by aligning service standards with customer commitment and to ensuring customers have access to a secure gas supply by pursuing new sources of natural gas and storage opportunities.

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,
- pursuing marketing and storage opportunities that optimize existing assets,
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets, and
- increasing the scale of the wind power business in locations near existing Enbridge infrastructure.

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

Rabaska LNG Facility

Enbridge, Gaz Metro and Gaz de France are continuing development of the previously announced Rabaska LNG terminal to be located on the St. Lawrence River in Levis, Quebec. The Levis municipal council has reversed an earlier decision opposing the project and are now fully supportive. Options for the required land have been secured and environmental filings were filed with federal and Quebec authorities in January 2006. The partners are in the process

of developing definitive supply and market agreements. The project is expected to cost approximately $840 million in total.

Goreway Power Project

The Company, in partnership with Sithe Global Power, L.L.C., has been selected by the Ontario Power Authority (OPA) to enter into negotiations to develop a 880-megawatt gas-fired power generation plant in Brampton, Ontario. The new plant would provide needed electricity to the Western Greater Toronto Area. Enbridge would hold a 25% interest in the project, which would provide the Company with an entry point into the gas-fired power generation business in a geographical area already served by the Company's largest gas distribution business, EGD.

Ontario Wind Project

Enbridge will be developing 200 megawatts of wind power on the eastern shore of Lake Huron in Ontario. Construction will commence in mid-2006 and total capital expenditures are expected to be approximately $400 million. Enbridge has entered into a 20-year electricity purchase agreement with the OPA for all of the power produced by the project. Enbridge currently has ownership in three wind power projects, which generate over 70 megawatts, in total.

Capital Expenditures

In order to support continuing customer growth, expansion of EGD's network on an ongoing basis is required. In addition, as part of its 2006 rate application, EGD has requested the OEB's approval for an accelerated program to replace the remaining cast iron mains with polyethylene mains. If the OEB approves the request for the accelerated cast iron main replacement program along with certain other requested capital expenditures, total capital expenditures during 2006 will be approximately $460.0 million, as compared to the annual capital expenditures in recent years of between $250.0 million to $300.0 million a year.

Capital expenditures in other Gas Distribution and Services businesses, including the Ontario Wind Project, described above, are expected to be approximately $240 million in 2006.

Enbridge Gas Distribution Legal Proceedings

Class Action Lawsuit — late payment penalties

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against EGD by a customer with respect to late payment penalties. The Supreme Court of Canada determined that EGD would be required to repay a portion of amounts paid to it as late payment penalties from April 1994. The total amount of late payment penalties billed between April 1994 and February 2002 (when EGD's late payment penalty was revised), was approximately $74 million, of which a portion may be eligible for repayment. The amount payable is not determinable at this time. The Supreme Court has directed that a lower court determine the amount payable. Case conferences were held before a judge of the Ontario Supreme Court in August and December 2004 and March 2005 to discuss the remaining outstanding issues following the Supreme Court's decision. Further court proceedings to determine the amount payable and other related issues are likely to be held in early 2006.

Late payment penalty revenues are included in EGD's estimate of revenues for the year and therefore accrue to the benefit of all customers, reducing the cost of providing distribution services. The OEB approves these estimates and the resulting rates each year. EGD intends to apply to the OEB for recovery of any amount payable that results from this action.

Bloor Street Incident

EGD has 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. The maximum possible fine upon conviction on all charges would be $5.0 million in aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion has also been called, but the proceedings are stayed pending resolution of the TSSA and OHSA matters. The courts have not yet ruled upon any of the charges laid under the TSSA or the OHSA, and thus it is not possible at this time to predict or comment upon the potential outcome. The trial in respect of these charges commenced January 3, 2006. EGD does not expect the outcome of these civil actions to result in any material financial impact.

Business Risks

The risks identified below are specific to the Gas Distribution and Services business. General risks that affect the Company as a whole are described under Risk Management.

Enbridge Gas Distribution

The business risks inherent in the natural gas distribution industry impact the ability of EGD to realize the revenue level required to generate the allowed return on equity. These business risks include obtaining timely and adequate rate relief, accuracy in forecasting, and then realizing, natural gas distribution volumes.

Volume Risks

Since customers are billed on a volumetric basis, the ability to collect the total revenue requirement (the cost of providing service) depends upon achieving the forecast distribution volume established in the annual ratemaking process. The probability of realizing such volume is contingent upon four key forecast variables: weather; economic conditions; the price of gas and the pricing of competitive energy sources; and the number of customer additions.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 78% (2004 — 77%) of total distribution volume. Weather during the year, measured in degree days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating. In 2005, degree days closely approximated those forecast, resulting in no weather related volume variance.

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 annual average consumption. Average annual gas usage has declined by 1.0% per annum over the last 10 years, reflecting consistent customer conservation efforts.

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 volumes 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 approved return on equity due to other forecast variables such as, mix of sales and transportation of gas for customers, the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

Rate Relief

Through the regulatory process, the OEB approves the return on equity, which EGD is allowed to earn, in addition to various other aspects of utility operations.

Rate relief could be pursued for significant unforecasted amounts allowing EGD to recover the costs of providing and maintaining the quality of its service while achieving the allowed rate of return on rate base.

EGD does not profit from the price of the natural gas commodity nor is it at risk for the difference between the actual cost of gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition.

Forecasting Accuracy

Forecasting accuracy is a risk since rates are established in advance, based on anticipated distribution volume by class of customer. Forecasts are also made for the future cost of capital including the forecast yield rate for long-term Government of Canada Bonds used in the determination of the return on equity. Through the forecasting process, it is intended that any changes in cost of service, regardless of whether they are caused by inflation or by level of business activity, would be reflected in new rates approved for that fiscal year based on the anticipated distribution volume.

Franchise Rights

To date, the OEB has upheld the Company's exclusive right to serve all end users within its franchise area, under its franchise agreements. Similar franchise agreements are held by peer companies such as Union Gas Limited (UGL). On January 6, 2006, the OEB granted Greenfield Energy Corporation, a potential power-plant customer of UGL, the right to physically bypass UGL's distribution network within UGL's franchise area, in order to serve its own power-plant. The OEB's decision to not uphold exclusive franchise rights of a local distribution utility in Ontario is unprecedented. However, the OEB characterized this decision as transitional, and has set up a rates proceeding to assess the service requirements of gas fired generation in the province of Ontario. At the present time, the Company is unable to assess the possible future financial implications given the recentness of this decision and potential outcomes from the above rates proceeding.

Gas Services

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago and between Chicago and Dawn. To the extent that the difference in the price of natural gas in the various locations is not greater than the cost of transportation between Alberta and Chicago or Dawn, earnings will be negatively affected.

Aux Sable

Earnings from Aux Sable were exposed to the effect of spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. This risk was mitigated by lower heat content requirements on downstream pipelines, which commenced in 2004, and the use of commodity hedges, which opportunistically locked in positive margins when forward markets allow.

Demand for NGL is influenced by overall weather and economic activity because NGL are used to make energy products for home and industrial heating and as feedstock for the petrochemical industry, among other things. Because Aux Sable's earnings are dependent, to a large degree,

on commodity prices, earnings can be volatile. To reduce this volatility, Aux Sable entered into hedge transactions to fix the spread between natural gas and NGL prices. Starting in 2006, this risk will be eliminated by Aux Sable's contract with BP.

INTERNATIONAL

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
CLH	**61.6**	48.6	46.3
OCENSA/CITCol	**32.8**	33.0	32.3
Other	**(7.0)**	(8.0)	(6.3)
	87.4	73.6	72.3

Business Activities

International includes earnings from the Company's 25% interest in Compañia Logistica de Hidrocarburos (CLH), Spain's largest refined products transportation and storage business, and OCENSA, a crude oil pipeline in Colombia. Earnings also include fees earned from technology and consulting services provided by Enbridge Technology Inc.

CLH

The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network located throughout Spain. Earnings are based on a fee for service tariff, adjusted annually for inflation, and are dependent on throughput volumes and storage levels.

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access non-discriminatory basis. The system consists of over 3,400 kilometers of pipelines and 39 storage facilities located throughout the country. CLH provides product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships. CLH also offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition, allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, the aviation fuel business will continue. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where most of Spain's crude oil and refined products are imported.

Earnings from CLH are directly impacted by the demand for refined products including diesel and other fuels for transportation purposes. Economic growth in Spain over the last decade has been one of the highest in the European Union, which has led to increasing demand for energy, including refined products. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH plans to expand its system over the next several years in order to meet the continued growth expected in this region. This expansion, which includes looping of both the northern and southern main lines, will be constructed in phases to match the expected growth in volumes.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, a cost investment on which the Company earns a fixed return. OCENSA is of one of two crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages it and earns a fee for this service, which includes incentive earnings for operating performance.

Results of Operations

Earnings for the year ended December 31, 2005 are $87.4 million compared with $73.6 million for the year ended December 31, 2004. The increase results primarily from a $7.6 million gain on the sale of land in CLH. Operating results at CLH are also improved due to higher volumes and increased average tariffs and storage revenues.

In 2004, increased earnings of $1.3 million compared with 2003 were due to stronger results from CLH and from CITCol, operator of the OCENSA pipeline, which exceeded certain operational performance targets resulting in additional incentive income. Operating results from CLH reflected increased volumes in 2004 compared with 2003 due to greater demand for refined products throughout Spain, lower operating costs and the translation impact of the stronger Euro.

Other costs include other administration and business development costs.

Strategy

Enbridge plans to increase its business development activity in Europe and Latin America. In Europe, Enbridge will seek opportunities to acquire assets or develop greenfield projects that facilitate expected supply flow through eastern European countries to satisfy growing western European demand. In Colombia, where the Company has substantial expertise, Enbridge will focus on acquiring additional assets.

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.

CORPORATE

(millions of Canadian dollars)	**2005**	2004	2003
Corporate	**(63.9)**	(81.3)	(76.6)

The Corporate segment includes corporate financing costs, business development activities not attributable to a specific business segment and other corporate activities.

Corporate costs are $63.9 million for the year ended December 31, 2005 compared with $81.3 million for the year ended December 31, 2004. Corporate costs are lower in 2005 reflecting lower interest expense due to lower rates. Also, business development costs were higher in 2004.

The 2004 corporate costs include a higher expense for stock-based compensation, compared with 2003, and increased business development activity, partially offset with lower interest expense.

LIQUIDITY AND CAPITAL RESOURCES

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities, which totaled $3,454.8 million on December 31, 2005, and access to capital markets in Canada and the United States for the issuance of long-term debt, equity, or other securities are expected to be sufficient to satisfy liquidity and capital expenditure requirements.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2005, including short-term borrowings, but excluding non-recourse short and long-term debt, was 64.5%, compared with 65.1% at the end of 2004. The improved debt to capitalization ratio reflects the Company's continuing commitment to maintaining a strong balance sheet.

The Company's current liabilities routinely exceed current assets. This deficit is funded through cash from operations, which are typically about double the balance of the deficit in a given year. For example, at the end of 2003, the working capital deficit was $270.5 million. During 2004, operations generated $886.7 million cash which easily funded the deficit. The Company expects this trend to continue.

The Company's cash balance at the end of the year includes $16.4 million (2004 — $6.0 million; 2003 — $18.7 million) held in trust in joint ventures, pursuant to finance agreements within the joint ventures.

Operating Activities

Cash from operating activities increased to $903.5 million for the year ended December 31, 2005 from $886.7 million for the year ended December 31, 2004 and $368.5 million for the year ended December 31, 2003.

(millions of Canadian dollars)	**2005**	2004	2003
Earnings net of non-cash items	**1,300.9**	1,027.8	938.3
Changes in operating assets and liabilities	**(397.4)**	(141.1)	(569.8)
Cash Provided by Operating Activities	**903.5**	886.7	368.5

Cash provided by earnings net of non-cash items, was $1,300.9 million for the year ended December 31, 2005, compared with $1,027.8 million and $938.3 million for 2004 and 2003, respectively. This $273.1 million increase in cash from 2004 reflects special dividends from Noverco, cash generated by Enbridge Offshore Pipelines, acquired on December 31, 2004, and increased earnings from EGD.

In 2004 cash from earnings net of non-cash items reflected increased contributions from the Enbridge System, due to the Terrace Phase III expansion placed into service on April 1, 2003, from EGD, due to increased rates in 2004, and from Aux Sable, due to improved fractionation margins in 2004 compared with 2003.

Changes in operating assets and liabilities were $258.7 million lower in 2005 compared with 2004. The majority of this change is in EGD where higher commodity prices increased accounts receivable and inventory.

The variance in changes in operating assets and liabilities from 2003 to 2004 was due to the draw down of gas in storage in EGD from September 30, 2003 (the prior year end) to December 31, 2004 (the new year end). Gas in storage is typically lower at the end of December as winter demand has drawn down some of the supply.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2006.

Investing Activities

Cash used for investing activities for the year ended December 31, 2005 was $833.0 million compared with $999.7 million in 2004. In 2005, the majority of cash spent on investing was for additions to property, plant and equipment, primarily in EGD. The increase in additions to property, plant and equipment in 2005, compared with 2004, is due to increased expenditures on capital projects, such as the reversal of the Spearhead Pipeline and the Ontario Wind Power Project.

In 2005, the Company made minor acquisitions throughout the year amounting to $88.6 million whereas, in 2004, $833.9 million was used for acquisitions including Enbridge Offshore Pipelines, acquired for $743.4 (net of cash acquired) and other minor acquisitions. Cash proceeds from the sale of the investment in AltaGas partially offset the use of cash for acquisitions in 2004.

Also in 2005, the Company made contingent payments to the former owners of the Company's 25% interest in CLH because CLH met cumulative volume targets. These payments make up the majority of the 2005 expenditure on long-term investments. In 2004, the Company also made smaller contingent payments to the former owners of the 25% interest in CLH.

In 2003, investing activities provided $259.5 million primarily as a result of the proceeds received on the sale of assets to EIF. Also, 2003 reflected the repayment by EEP of short-term loans from the Company. Additions to property, plant and equipment were primarily related to EGD.

Financing Activities

In 2005, financing activities used cash of $22.1 million compared with a source of $114.4 million in 2004.

During 2005, the Company issued $1,020.1 million new long-term debt in the form of medium-term notes and senior notes. This new debt replaced higher interest rate medium-term notes, which matured during 2005, and short-term debt, primarily commercial paper. The repayment of short-term debt was partially offset by an increase in short-term borrowings at EGD. EGD uses short-term borrowings to finance working capital, which was higher at the end of 2005 due to increased commodity prices.

Dividends on common shares have increased again in 2005 due to an increased number of common shares outstanding and a higher dividend rate.

In 2004, cash was generated through a net issuance of $438.0 million of debt, partially offset by the payment of dividends. The Company also repaid $350.0 million of preferred securities at the end of 2004. Financing activity in 2003 included the payment of dividends and a net reduction in debt through utilization of the cash proceeds from the sale of assets to EIF.

Expected Capital Expenditures

The numerous potential 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 $1,130 million during 2006 on capital projects. The Company expects to finance these expenditures through cash from operating activities and additional debt, if required.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued 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	6,662.5	400.0	788.4	950.0	4,524.1
Non-recourse long-term debt	1,563.0	66.7	155.7	244.5	1,096.1
Capital and operating leases	85.0	5.1	10.3	11.0	58.6
Long term contracts	822.5	190.9	217.0	196.4	218.2
Total Contractual Obligations	9,133.0	662.7	1,171.4	1,401.9	5,897.0

RISK MANAGEMENT

The Company's business activities are subject to both financial and operational risks. The Company has formal risk management policies and risk management systems designed to mitigate these risks.

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 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 Market Price Risk metric utilized within that policy is Earnings at Risk. It is an objective, statistically derived risk metric that measures the maximum earnings loss that could result from adverse market price movements over a specified time horizon within a pre-determined level of statistical confidence, under normal market conditions.

The Company uses derivative financial instruments to manage its exposures to within these policy limits. The following summarizes the types of risks to which the Company is exposed and the hedging programs implemented:

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and Euro denominated investments, where both carrying values and earnings are subject to foreign exchange risk. Furthermore, the Company is exposed to the economic risk on the conversion of the foreign currency denominated cash flows. The Company has a hedging policy to eliminate 50% to 70% of the long-term economic exposure related to its foreign currency denominated cash flows. It will also hedge shorter term anticipated foreign currency capital expenditures. The Company hedges certain of its foreign currency denominated net equity investments with the use of cross currency swaps, par forward contracts, and foreign currency denominated debt. The return of capital on the cost accounted for investment in OCENSA also is hedged with cross currency swaps.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on 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 it stays within its Board of Directors approved policy limit band of 15% to 25% floating rate debt within the consolidated portfolio. Fixed to floating swaps are also used from time to time to manage this position and optimize the Company's debt portfolio. The Company is also exposed to fluctuations in interest rates on anticipated fixed rate debt issuances. Also, the Company enters into interest rate derivatives to hedge a portion of the interest cost of future debt issues related to specific capital projects.

Commodity Price Risk

The Company uses natural gas price swaps, futures, options and collars to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector pipelines. The Company also uses derivative instruments to fix the value of variable price exposures that arise from commodity storage arrangements and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable, it is exposed to the price differential between natural gas and natural gas liquids (NGL). This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of natural gas and NGL are fixed with swaps, or capped or collared with options. Starting in 2006, Aux Sable's contract with BP will eliminate this risk.

The Company has also entered into over-the-counter swap agreements to convert the price of power in Alberta and Ontario from a floating rate to a fixed rate per megawatt hour.

Natural Gas Supply Management

Customers of EGD are exposed to changes in the price of the natural gas commodity. A portion of the future natural gas supply requirements is hedged using natural gas swaps and options that manage the price of natural gas, as allowed by the OEB. Since the cost of the natural gas commodity is paid by customers, this risk mitigation strategy is for the account of the customers. The OEB monitors the policies, procedures, and results of this hedging program.

Fair Values of Derivative Instruments

The following table summarizes the financial instruments outstanding at year end for the purposes of mitigating the risks as described above. Amounts shown in the table below under Fair Value Receivable/(Payable) represent unrecognized gains/(losses) associated with these instruments.

(millions of dollars unless otherwise noted)

December 31,	**2005**			2004		
	Notional Principal or Quantity	**Fair Value Receivable/ (Payable)**	**Maturity**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**307.3**	**(2.9)**	**2007-2022**	535.8	(51.1)	2005-2022
Euro cross currency swaps	**447.6**	**39.6**	**2006-2019**	493.5	(51.3)	2005-2019
Forwards (cumulative exchange amounts)	**1,640.1**	**241.6**	**2006-2022**	1,740.3	181.0	2005-2022
Interest rates						
Interest rate swaps	**954.4**	**(1.1)**	**2006-2029**	1,069.0	1.5	2005-2029
Forward interest rate swaps	**150.0**	**1.2**	**2007**	200.0	—	2006
Energy commodities						
Natural gas (bcf)	**130.5**	**18.1**	**2006-2011**	107.8	(1.0)	2005-2010
Natural gas supply (bcf)	**27.3**	**(6.7)**	**2006**	34.9	(28.1)	2005
Power (MW/H)	**28.0**	**0.8**	**2006-2017**	—	—	—

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $91.0 million (2004 — $214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2007. These instruments are recorded at fair value and have a fair value payable of $14.3 million as at December 31, 2005 (2004 — $28.8 million).

The fair values of derivatives have been estimated using year-end market information. These fair values approximate the amount that the Company would receive or pay to terminate the contracts.

Credit risk on derivative financial instruments amounted to $351.8 million as at December 31, 2005 (2004 — $211.2 million) with no significant concentration with any single counterparty.

Fair Values of Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties, calculated at the reporting date, to settle these instruments. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The estimated fair values of all other financial instruments are based on quoted market prices or, in the absence of specific market prices, on quoted market prices for similar instruments and other valuation techniques.

Total Debt

(millions of Canadian dollars)

December 31,	**2005**		2004	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Liquids Pipelines	**1,039.4**	**1,201.4**	913.4	1,037.8
Gas Distribution and Services	**1,786.7**	**2,184.2**	1,823.4	2,168.9
Corporate	**3,854.2**	**4,076.3**	4,020.4	4,275.6
	6,680.3	**7,461.9**	6,757.2	7,482.3

The fair value of debt does not include the effects of hedging. Non-recourse debt of joint ventures has a carrying value of $1,668.1 million (2004 — $695.4 million) and fair value of $1,775.1 million (2004 — $796.4 million).

Operating Risks

Environmental, Health and Safety Risk

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 accidents 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.

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other risks involved in operating a comprehensive pipeline system 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 keep on hand 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, thereby impacting earnings. The Company has an extensive program to manage system integrity, which includes the development and use of predictive and detective 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.

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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Rate Regulation

The Company follows generally accepted accounting principles, which may differ for regulated operations from those otherwise expected in non-regulated businesses. In general, these differences occur when the regulatory agencies render decisions that involve the timing of revenue and expense recognition and ensure that the actions of the regulatory authorities, which may create economic assets and liabilities, have been reflected in the financial statements.

The recognition of these items in the Company's financial statements depends on its expectation of the future actions of the regulatory authorities. For example, some of the Company's rate-regulated businesses do not record future income taxes because the regulatory authorities prescribe the use of the taxes payable method for rate-making purposes and there is reasonable expectation that future income taxes will be recovered as they become payable.

If regulatory agencies' future actions are different from the Company's expectations, the timing and amount of the recovery of liabilities or refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

The Company's operations are regulated under three main regulatory regimes. Enbridge System negotiates tolls with its shippers under either the ITS or for specific expansions and these agreements are approved by the NEB. EGD files a rate application with the OEB, for its approval. Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines have negotiated transportation services contracts with shippers that incorporate a FERC approved toll and tariff structure. Descriptions of each of these regulatory regimes, including how tolls and rates are set, how costs are recovered, and how returns are calculated are included in the sections describing each of these businesses.

In 2005, the Company adopted the new accounting guideline, *Disclosure by Entities Subject to Rate Regulation*. This guideline requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the entity's financial statements.

Revenue Recognition

Generally, revenues are recorded when products have been delivered or services have been performed. Certain of the Liquids Pipelines, Gas Pipelines and gas distribution operations within Gas Distribution and Services are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts. For rate-regulated operations, revenue is recognized in a manner that is consistent with the underlying rate agreements as approved by the regulatory authority.

The Company has entered into a long-term (30 year) take or pay contract with a shipper on the Athabasca System and revenues are recorded based on the contractual terms rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning rate of return on equity, based on an assumed debt/equity ratio and level of operating costs of providing service to the shipper on the pipeline. The committed volumes on the pipeline and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate the Company for the debt and equity returns, as well as the cost of providing service. The Company is recording a receivable in these years. This ensures that the revenue recognized each period is in accordance with the underpinning return. This

receivable is contractually guaranteed from the shipper and will be collected in the later years of the contract.

The recording of revenues under the terms of approved regulatory agreements of the Enbridge System may also not necessarily match the cash tolls. The agreements, and all their terms and conditions, are subject to the review and approval by the pipeline's regulator, the NEB. During their terms, the agreements govern both current and future shippers on the pipeline. The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements and other contractual arrangements with customers.

Revenues are recognized based on these agreements' definitions of an allowed revenue requirement and are generally not impacted by the level of cash tolls collected. This basis may affect the timing of recognition of revenues from that otherwise expected under generally accepted accounting principles for companies that are not rate-regulated.

Tolls are calculated in accordance with the agreements which stipulate that tolls are to be established each year based on capacity as per the various agreements and/or the allowed revenue requirement. Where actual volumes on the pipeline fall short of agreed capacity and Enbridge is unable to collect its annual revenue requirement, such deficiency is rolled into the subsequent year's tolls for collection from toll payers at that time and a receivable is recognized.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Certain amounts are deferred for recovery with the approval of the regulator and are not included in revenues or expenses that would be recognized in the income statement, absent the actions of the regulator. The regulator, through the rate-making process, allows certain variances between approved and actual expenses or income to be recovered from customers in future periods. The deferred amounts are not included in the calculation of rates to be billed to customers. While there are numerous deferral accounts approved by the regulator, the largest of these typically is the difference between the approved and actual cost of gas, which is not included in the cost of service used to determine rates, and therefore not included in revenues. The recovery of this difference is recognized on the statement of financial position, at the formal direction of the regulator, with no impact on revenues or expenses in the income statement. EGD has no exposure to the cost of gas, as it is a flow through cost that is borne directly by the ratepayer.

CHANGES IN ACCOUNTING POLICIES

Consolidation of Variable Interest Entities

Effective January 1, 2005 the Company adopted, without restatement of prior periods, the new CICA accounting guideline for Consolidation of Variable Interest Entities. This new standard requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest as well as a preferred unit investment that has no voting rights, a stated par value and a 30-year maturity. The preferred units earn a return that is equivalent to the cash distributions per unit to the equity unit holders and are classified as a liability in EIF's financial statements.

Financial Instruments, Hedging Relationships and OCI

New accounting standards will be in effect for fiscal years beginning on or after October 1, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

EITF 04-5 — Partnership Consolidation

In June 2005, the U.S. Emerging Issues Task Force, or EITF, reached a consensus on EITF issue 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (EITF 04-5), addressing when a general partner, or general partners as a group, control and should therefore, consolidate a limited partnership. Under EITF 04-5, a sole general partner is presumed to control a limited partnership when certain conditions are met. As a result, for the first reporting period beginning after December 15, 2005, it is expected that the Company will be required to include the accounts of Enbridge Energy Partners, L.P. for U.S. GAAP purposes.

Enbridge continues to equity account for its interest in EEP under Canadian GAAP.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in the rules of the Securities and Exchange Commission and the Canadian Securities Administrators) and concluded that the Company's disclosure controls and procedures were effective as of December 31, 2005 and in respect of the 2005 year end reporting period.

QUARTERLY FINANCIAL INFORMATION[1]

(millions of Canadian dollars, except for per share amounts)

2005	First	Second	Third	Fourth	Total
Revenue	**2,555.8**	**1,527.4**	**1,657.1**	**2,712.8**	**8,453.1**
Earnings applicable to common shareholders	**220.6**	**93.6**	**67.8**	**174.0**	**556.0**
Earnings per common share	**0.66**	**0.27**	**0.20**	**0.52**	**1.65**
Diluted earnings per common share	**0.65**	**0.27**	**0.20**	**0.51**	**1.63**
Dividends per common share	**0.2500**	**0.2500**	**0.2500**	**0.2875**	**1.0375**

(millions of Canadian dollars, except for per share amounts)

2004	First	Second	Third	Fourth	Total
Revenue	1,709.8	2,158.8	1,615.6	2,323.6	7,807.8
Earnings applicable to common shareholders	112.4	248.4	179.7	104.8	645.3
Earnings per common share	0.34	0.74	0.54	0.31	1.93
Diluted earnings per common share	0.34	0.73	0.54	0.30	1.91
Dividends per common share	0.22875	0.22875	0.22875	0.22875	0.9150

1 Financial Highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.

Quarterly operating revenue fluctuates primarily due to the seasonality of the Company's gas distribution business. Prior to October 1, 2004, this business had a September 30 year end,

which resulted in consolidation by the Company on a quarter lag basis. Therefore, peak revenues were recorded in the Company's second quarter, which represented Enbridge Gas Distribution's winter months. Starting in October 2004, EGD has changed to a December 31 year end and, as a result, the Company's consolidated fourth quarter results for 2004 include the results of EGD for the six months ended December 31, 2004.

Effective October 1, 2004, EGD's seasonal rates were replaced with a uniform annual rate. The impact of this change has resulted in lower earnings in the winter months (fourth and first quarters), offset by higher earnings in the summer months (second and third quarters), causing a shift in earnings between quarters but no earnings impact on a 12 consecutive month basis.

The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second quarter of 2004. Significant items that impacted 2005 and 2004 quarterly earnings are as follows:

- Fourth quarter earnings in 2005 include a gain of $7.6 million on the sale of land in CLH and a dilution gain of $4.3 million in EEP.
- Third quarter earnings in 2005 were negatively impacted by Hurricanes Katrina and Rita and by non-cash losses on the fair value of derivatives in EEP.
- First quarter earnings in 2005 include dilution gains in EEP and within Noverco totaling $11.9 million.
- Fourth quarter earnings in 2004 include the additional "fifth quarter" for EGD and other gas distribution businesses that account for an increase of $57.2 million. This was partially offset by an impairment loss of $8.2 million on the Calmar gas plant.
- Third quarter earnings in 2004 include a $97.8 million gain on the sale of the Company's investment in AltaGas offset by the remaining reversal of $25.6 million related to unbilled revenue.
- Second quarter earnings in 2004 reflect the $9.4 million partial reversal of the $35.0 million of unbilled revenue recorded in the first quarter of 2004 and a dilution gain of $8.0 million related to AltaGas.
- First quarter earnings in 2004 reflect a $47.6 million charge to earnings resulting from an increase in the Ontario tax rate and corresponding revaluation of future income taxes, as well as an increase of $35.0 million for unbilled revenue, consistent with a change in the estimation process in 2004, both within EGD.

FOURTH QUARTER 2005 HIGHLIGHTS

Fourth quarter earnings for 2005 are $174.0 million, compared with $104.8 million in 2004. The increase in earnings reflects a higher contribution from the gas distribution utility. Although the prior year quarter includes six months of earnings for the gas distribution utilities, the additional quarter, July 1 to September 30, 2004, is seasonably a summer loss quarter and reduced earnings in the fourth quarter of 2004. Also, in the fourth quarter of 2004, an impairment loss of $8.2 million was recognized on the Calmar gas plant.

SUPPLEMENTARY INFORMATION

Outstanding Share Data	Number outstanding
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares — issued and outstanding (voting equity shares)	349,533,852
Total issued and outstanding stock options (6,164,141 vested)	10,994,291

Outstanding share data information is provided as at January 23, 2006.

RELATED PARTY TRANSACTIONS

Neither EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. Vector Pipeline uses the services of Enbridge to operationally manage its business. Amounts for these services, which are charged at cost in accordance with service agreements are:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
EEP	**184.7**	173.0	128.9
EIF	**—**	9.4	4.7
Vector Pipeline	**4.1**	4.4	3.3
	188.8	186.8	136.9

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline Canada and Vector Pipeline. EGD is charged market prices for these services:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
Alliance Pipeline Canada	**40.4**	50.6	40.7
Vector Pipeline	**29.2**	39.1	23.2
	69.6	89.7	63.9

CustomerWorks Limited Partnership, a joint venture, provides customer care services to EGD under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services. CustomerWorks also rents an automated billing system from ECS, a subsidiary of the Company. Amounts charged by (to) CustomerWorks:

(millions of dollars)

Year ended December 31,	**2005**	2004	2003
EGD	**103.6**	127.0	95.5
ECS	**(8.7)**	(22.5)	(25.5)
	94.9	104.5	70.0

Enbridge Gas Services Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP.

(millions of dollars)

Year ended December 31,	2005	2004	2003
Enbridge Gas Services Inc.			
Purchases	**48.1**	30.7	33.6
Sales	**(4.7)**	(8.8)	(1.3)
	43.4	21.9	32.3

Enbridge Gas Services Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline Canada and Vector Pipeline:

(millions of dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline Canada	**9.1**	8.8	8.4
Vector Pipeline	**0.7**	0.5	0.6
	9.8	9.3	9.0

Enbridge Gas Services (US) Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline US and Vector Pipeline:

(millions of dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline US	**7.1**	7.6	7.8
Vector	**9.5**	9.8	10.5
	16.6	17.4	18.3

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP.

(millions of dollars)

Year ended December 31,	2005	2004	2003
Purchases	**9.7**	—	—
Sales	**—**	(2.3)	—
	9.7	(2.3)	—

The receivable from affiliate of $177.0 million (2004 — $171.7 million) resulted from the sale of Enbridge Midcoast Energy to EEP. The note, denominated in U.S. dollars, bears interest at 6.6% and matures in 2007. The balance on December 31, 2005 was US$151.9 million (2004 — US$142.1 million). Interest income related to the affiliate receivable was $11.7 million (US$9.4 million), $11.8 million (US$9.0 million) and $21.7 million (US$15.5 million), in 2005, 2004 and 2003, respectively. The fair value of the receivable at December 31, 2005 is $176.8 million.

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable; where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates. Prices are determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

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

Dated February 1, 2006

When used in this document, the words “anticipate”, “expect”, “project”, “believe”, “estimate”, “forecast” and similar expressions are intended to identify forward-looking statements, which include statements relating to pending and proposed projects. Such statements are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, weather and economic conditions and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers.

EXHIBIT 99.6

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS

We hereby consent to the incorporation by reference in the registration statements (Nos. 333-97305, 333-13456 and 333-6436) on Form S-8, (No. 33-77022) on Form F-3 and (No. 333-122526) on Form F-10 of Enbridge Inc. (the "Corporation") of our report dated February 1, 2006, relating to the financial statements of the Corporation as at December 31, 2004 and 2005 and for the years then ended, which report is included in Exhibit 4 to this Annual Report on Form 40-F of the Corporation.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta
February 1, 2006