Table of Contents

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, 2003 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:

171,947,576 Common shares (as at December 31, 2003)

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

TABLE OF CONTENTS

DISCLOSURE CONTROLS AND PROCEDURES
AUDIT COMMITTEE FINANCIAL EXPERT
CODE OF ETHICS
PRINCIPAL ACCOUNTANT FEES AND SERVICES
OFF-BALANCE SHEET ARRANGEMENTS
TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS
IDENTIFICATION OF THE AUDIT COMMITTEE
FORWARD-LOOKING STATEMENTS
UNDERTAKING
SIGNATURES
EXHIBIT INDEX
Exhibit 1
Exhibit 2
Exhibit 3
Exhibit 4
Exhibit 5
Exhibit 6
Exhibit 7

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. D. Arledge and W. R. Fatt, members of the Audit Committee, each qualify as an audit committee financial expert (as defined in Item 401 of Regulation S-K 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. Arledge and Fatt 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.

On October 30, 2003, 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.

The following table sets forth the fees paid to PwC for the financial years ended December 31, 2002 and 2003.

	Year ended December 31	
	2003	2002
Audit Fees	$ 976,600	$1,249,550
Audit-Related Fees	365,000	26,000
Tax Fees	170,240	81,300
All Other Fees	75,750	494,610
Total Fees	$1,587,590	$1,851,460

The audit-related fees are primarily for prospectus filings and services related to the review of the Registrant's processes and procedures for ensuring compliance with the *Sarbanes-Oxley Act of 2002*. Tax fees are primarily for tax compliance and tax advisory services. All other fees are primarily for advisory services. In 2002, approximately 82% of the all other fees amount related to a working capital audit performed in connection with the disposition of the Registrant's energy services business.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements as defined by Item 303(a)(4)(ii) of Regulation S-K 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	4,693.1	450.0	968.6	589.3	2,685.2
Non-recourse long-term debt	725.4	32.5	84.4	72.0	536.5
Non-recourse capital leases	61.2	1.7	3.6	3.6	52.3

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 D.A. Arledge, E.S. Evans, W.R. Fatt 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, 2003, dated April 12, 2004, 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: April 23, 2004

By: /s/ “Blaine G. Melnyk”

Blaine G. Melnyk
Corporate Secretary & Associate General Counsel

Table of Contents

EXHIBIT INDEX

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

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

3. Annual Information Form of the Registrant dated April 13, 2004.

4. Audited financial statements of the Registrant and notes thereto for the fiscal years ended December 31, 2002 and 2003 and Auditor's Report thereon.

5. Management's Discussion and Analysis of the Registrant for the year ended December 31, 2003 dated February 24, 2004.

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

7. Report on Form 6-K of the Registrant dated April 23, 2004.

EXHIBIT 1

CERTIFICATIONS

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 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 report;

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

4. The issuer's other certifying officer(s) 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 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(s) and I have disclosed, based on our most recent evaluation, to the issuer's auditor and the audit committee of issuer's board of directors (or 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: April 23, 2004

/s/ Patrick D. Daniel

Patrick D. Daniel
President & Chief Executive Officer

EXHIBIT 1

CERTIFICATIONS

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 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 report;

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

4. The issuer's other certifying officer(s) 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 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(s) and I have disclosed, based on our most recent evaluation, to the issuer's auditor and the audit committee of issuer's board of directors (or 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: April 23, 2004

/s/ Stephen J. Wuori

Stephen J. Wuori
Group Vice President & Chief Financial Officer

EXHIBIT 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 United States

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2003, 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 23rd day of April, 2004.

/s/ Patrick D. Daniel

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Patrick D. Daniel
President & Chief Executive Officer

EXHIBIT 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 United States

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2003, 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 23rd day of April, 2004.

/s/ Stephen J. Wuori

_____

Stephen J. Wuori
Group Vice President & Chief Financial Officer



ENBRIDGE INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2003
dated
April 13, 2004

ENBRIDGE INC.
ANNUAL INFORMATION FORM
For the Year Ended December 31, 2003

TABLE OF CONTENTS

		Page
Item 1	Cover Page	i
Item 2	Corporate Structure	1
Item 3	General Development of the Business	2
Item 4	Narrative Description of the Business	5
	Liquids Pipelines	5
	Gas Pipelines	11
	Sponsored Investments	11
	Gas Distribution and Services	12
	International	21
	Corporate	21
Item 5	Risk Factors	22
Item 6	Dividends	23
Item 7	Description of Capital Structure	24
Item 8	Market for Securities	26
Item 9	Directors and Officers	28
Item 10	Legal Proceedings	32
Item 11	Registrar and Transfer Agent	33
Item 12	Additional Information	34

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.

When used in this Annual Information Form, the words "anticipate", "believe", "estimate", "expect", "forecast", "project" and similar expressions are intended to identify "forward-looking statements" (within the meaning of the United States Private Securities Litigation Reform Act of 1995), which include statements relating to pending and proposed projects. Such statements reflect the Issuer'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. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, actual results may vary significantly from those described in this Annual Information Form.

ITEM 2

CORPORATE STRUCTURE

Incorporation of the Issuer

Enbridge Inc. (the Issuer or 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 Issuer, 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 Issuer.

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 Issuer 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.

Subsidiaries

Each subsidiary listed below is 100% owned, directly or indirectly, by the Issuer. Numerous subsidiaries, many of which are inactive, are omitted from the following list. Individually their total revenue and assets are less than 10% of the consolidated revenue and consolidated assets, respectively, of the Issuer and considered in the aggregate, their total revenue and total assets are less than 20% of the consolidated revenue and consolidated assets, respectively, of the Issuer.

Name	Jurisdiction of Incorporation
IPL System Inc.	Canada
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 Inc.	Canada

ITEM 3

GENERAL DEVELOPMENT OF THE BUSINESS

The Issuer's primary business activities are the transportation and distribution of energy. 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 a common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons.

- Gas Pipelines includes proportionately consolidated investments in transmission pipelines that transport natural gas.

- 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. From May 2001 to October 2002, the Company, through its subsidiary, Enbridge Pipelines Inc., owned 100% of Enbridge Midcoast Energy, which is now a wholly owned subsidiary of EEP. Enbridge Income Fund is a publicly traded income fund whose assets are a 50% interest in a gas transmission 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, as well as gas services operations, including the Company's proportionately consolidated investment in Aux Sable and natural gas gathering and processing operations through an equity investment in AltaGas Services Inc.

- 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 following paragraphs describe significant events and transactions in the development of the Issuer's business over the last three years.

On December 31, 2003, EEP, a sponsored investment of the Issuer, acquired natural gas gathering and processing assets in north Texas. The assets were purchased for cash of US$249.7 million.

On December 22, 2003, the Issuer announced the acquisition of several assets from Shell Pipeline Company LP and Shell Oil Products U.S. The acquisition consists primarily of two different pipelines and two crude oil storage terminals that are to be acquired by EEP for approximate consideration of US$115 million. Closing of this acquisition is anticipated to occur in the first quarter of 2004, subject to regulatory approvals and rights of first refusal.

Underground cavern storage facilities were placed into service on November 1, 2003. The Company commenced development of underground cavern facilities to provide crude oil storage services through a partnership with CCS Income Trust in 2002. The storage facilities are located near the Company's main pipeline terminal at Hardisty, Alberta and capacity is approximately three million barrels.

On October 1, 2003, the Company purchased an additional 15% interest in Vector Pipeline Partnership from Duke Energy 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. The Company provides operating services for Vector Pipeline Partnership, which consists of a natural gas transmission pipeline between Chicago, Illinois and Dawn, Ontario that has a delivery capacity of one billion cubic feet (bcf) per day. The pipeline commenced operations in late 2000.

In September 2003, the Company acquired 90% of the outstanding shares of CCPS Transportation L.L.C., owner of a 650-mile crude oil pipeline system extending from Cushing, Oklahoma to Chicago, Illinois. Of the total purchase price, $78.3 million was paid on the date of acquisition. Payment of the remaining US$65.0 depends upon completion of reversal of the flow of the pipeline and must be paid no later than December 31, 2004 to allow reversal to proceed. Upon reversal, which, subject to shipper and regulatory approvals, is expected to be completed in 2004, the pipeline will transport Canadian crude south from Chicago to Cushing, Oklahoma and will be renamed the Spearhead Pipeline.

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 before working capital adjustments of $20.6 million and transaction costs of $0.2 million.

Phase III of the Terrace Expansion Project (Terrace) was completed on April 1, 2003 at a cost of approximately $120 million on the Enbridge System and approximately US$193 million on the Lakehead System. Completion of Phase III has increased capacity by 140,000 barrels per day. Phase II was completed in 2002 and provided an additional 40,000 barrels per day of capacity at a cost of approximately $100 million. Phase I was completed in 1999, at a cost of $610 million on the Enbridge System and US$145 million on the Lakehead System, and provided added heavy crude oil capacity of 170,000 barrels per day.

During 2003, the Company 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 of these additional investments, the Company established joint control effective April 1, 2003. The Company's 50% interest in Alliance Pipeline Canada was sold to EIF in June 2003. During 2002, the Company purchased an additional 15.7% interest in the Alliance Pipeline and a 9.5% interest in Aux Sable for a total cost of approximately $315 million. The Alliance Pipeline commenced operations in late 2000 and delivers approximately 1.3 bcf per day of western Canadian natural gas to the U.S. Midwest states.

On October 17, 2002, the Company closed the sale of the United States assets of Enbridge Midcoast Energy, including the South Texas System and the Northeast Texas assets, to EEP for $1,279.4 million (US$820 million), including cash and the assumption of debt.

Concurrent with the US$820 million sale transaction, EEM, a subsidiary of Enbridge, completed an initial public offering of 9,000,000 shares representing limited liability company interests with limited voting rights. The net proceeds from the offering were used to purchase i-units, a new class of limited partnership interests, from EEP. The proceeds from the issuance of the I-units were used to finance a portion of the acquisition cost of the assets. In connection with the offering, Enbridge purchased 17.2% of the EEM shares, increasing its effective ownership in the Partnership to 14.1% from 12.9%. Subsequent to this transaction, the Company's effective interest in the Partnership decreased from 14.1% to 12.2% due to unit issuances by EEP, which the Company did not participate in. EEM has no assets or operations other than those related to the interest in EEP and, by agreement, will manage the business and affairs of EEP. The EEM shares trade on the New York Stock Exchange under the symbol "EEQ".

With respect to EEP's acquisition of the assets, a committee of independent members of the Board of Directors of Enbridge Energy Company, Inc., an indirect wholly-owned subsidiary of the Company and the general partner of EEP, negotiated the purchase price and terms of the transaction on behalf of EEP's public unitholders and recommended that the Board approve the transaction. The independent committee retained its own expert financial and legal advisors to assist in this process and the financial advisor rendered a fairness opinion in connection with the transaction.

In November 2002, the staff of the United States Securities and Exchange Commission (SEC) advised Enbridge, Enbridge Energy Company, Inc., EEM and EEP that they had commenced an informal inquiry into the US$820 million sale transaction and the initial public offering by EEM. The SEC staff has advised Enbridge that their principal focus includes the financial forecast made in connection with the US$820 million sale transaction and the price for the assets. The SEC staff has not asserted that Enbridge, EEP or EEM have acted improperly or illegally, and it has not indicated an intention to seek a formal order of investigation. Enbridge is cooperating fully with SEC staff. Based on an internal review of the forecast and terms of the transaction, Enbridge continues to believe that the financial forecast had a reasonable basis and the price for the assets was fair to EEP. Enbridge believes that the informal investigation will not have a material adverse effect on the financial condition of the Company.

Enbridge acquired Midcoast Energy Resources, Inc. (Enbridge Midcoast Energy) on May 11, 2001 for $561.8 million and the assumption of $406.0 million of long-term debt. Enbridge Midcoast Energy transports, gathers, processes and markets natural gas and other petroleum products. In January 2002, Enbridge Midcoast Energy acquired the South Texas System for $14.3 million. This system includes approximately 175 miles of natural gas gathering pipelines, a hydrogen sulfide treating plant and an inactive natural gas processing plant. In March 2002, Enbridge Midcoast Energy acquired natural gas gathering and processing facilities in northeast Texas (the Northeast Texas assets) from Sulphur River Gathering L.P. for approximately $290 million. The Northeast Texas assets consist of 1,100 miles of natural gas gathering pipelines and gas treating and processing plants. These assets were sold to EEP in October 2002 as previously disclosed.

During 2001, Enbridge and B.C. Gas Inc. created a limited partnership to develop and operate a new entity, CustomerWorks LP (CustomerWorks), that provides full-service customer management solutions to utilities, municipalities and retail energy companies across Canada. CustomerWorks provides services to more than 3.5 million customers including those from Terasen Gas, Enbridge Gas Distribution Inc. (Enbridge Gas) and Enbridge Gas New Brunswick. In August 2002, CustomerWorks outsourced the provision of its customer care services to a new entity owned by Accenture Inc.

The SunBridge wind power project was officially opened in June 2002. The $22 million project, which generates approximately 11 megawatts of electricity, is operated by Enbridge and was developed through a 50/50 partnership with Suncor Energy Inc. SaskPower is purchasing the wind-generated electricity for sale to the Government of Canada and other customers in Saskatchewan.

In May 2002, the Company closed the sale of the business operations that provide energy products and services to retail and commercial customers for cash proceeds of $1 billion. These operations include the water heater rental program; retail appliance, fireplace and water heater sales and service; mass market commercial plumbing, heating, ventilation and air conditioning; appliance repair and electrician contractor services in Canada and the United States; and the consumer financing operations.

In 2002, Enbridge acquired 25% of Compañia Logistica de Hidrocarburos CLH, S.A. (CLH) for approximately $430.8 million. CLH owns and operates the largest refined products pipeline network and storage facilities on the Spanish mainland and Balearic Islands. Contingent consideration of up to 84.3 million Euros ($137.2 million) will become payable over the next three years if certain minimum annual and cumulative volume targets are met.

The Issuer acquired an additional 34% interest in the Frontier Pipeline Company in the fourth quarter of 2001 for US$28.9 million, increasing Enbridge's interest to 77.8%. The Frontier Pipeline transports crude oil from Casper, Wyoming to the Salt Lake City area of Utah.

Enbridge is a 63% participant in Enbridge Gas New Brunswick, which was awarded the franchise for natural gas distribution in the Province of New Brunswick in September 1999. This investment provides the Issuer with a strategic presence in Atlantic Canada. Operations commenced with initial customer connections in March 2001.

ITEM 4

NARRATIVE DESCRIPTION OF THE BUSINESS

Revenues by Segment

(Canadian dollars in millions)	2003	2002	2001
Liquids Pipelines	**821.5**	787.7	722.9
Gas Pipelines	**222.1**	—	—
Sponsored Investments[1]	**—**	1,219.0	681.5
Gas Distribution and Services	**3,785.4**	2,513.5	2,645.7
International	**26.2**	27.2	30.8
Corporate	**0.1**	0.1	—
Revenues from continuing operations	**4,855.3**	4,547.5	4,080.9
Revenues from discontinued operations	**—**	181.9	463.0
Total Revenues	**4,855.3**	4,729.4	4,543.9

1. Earnings from EEP and EIF are accounted for as investment income and are therefore not included in revenues.

LIQUIDS PIPELINES

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

Liquids Pipelines Business

The Issuer has ownership in, and operates, the world's longest liquid petroleum pipeline system. The main pipeline system (the System) consists of the Enbridge System in Canada and the Lakehead System in the United States, which is owned by EEP. The Company has an equity investment in EEP that is included in Sponsored Investments. The System is the primary transporter of crude oil from 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 the Province of Ontario, as well as the Great Lakes region of the United States. A system owned by Enbridge Pipelines (NW) Inc. (NW System) transports crude oil from the Northwest Territories to the Enbridge System. The Athabasca System transports synthetic and heavy crude oil from the Athabasca and Cold Lake regions of Alberta to Hardisty, Alberta. In addition, the Issuer owns various feeder pipeline systems (Frontier, Toledo, Mustang and Chicap), which operate in the United States, as well as a 90% interest in the Cushing to Chicago Pipeline System (CCPS), which was acquired in the third quarter of 2003.

The Enbridge System extends approximately 1,200 miles from Edmonton, across the Canadian prairies, to the U.S. border near Gretna, Manitoba where it connects with the Lakehead System. The Lakehead System reconnects with the Enbridge System at the U.S. border near Sarnia, Ontario. The Enbridge System extends from Sarnia 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 National Energy Board (NEB). Total deliveries averaged 1,864,000 barrels per day in 2003.

The NW System extends approximately 540 miles between Norman Wells, Northwest Territories and Zama, Alberta. From Zama, crude oil is transported through the pipeline facilities of others to Edmonton, Alberta for delivery to refineries in the Edmonton area or to the Enbridge System or to other carriers for transportation to other Canadian or U.S. refineries. The NW System is regulated by the NEB and is subject to a negotiated

settlement and throughput agreement with its main shipper. Total deliveries averaged 26,600 barrels per day in 2003.

The Athabasca System, which is owned by Enbridge Pipelines (Athabasca) Inc. (Enbridge Athabasca), has a design capacity of 570,000 barrels per day and extends approximately 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 or other carriers for transportation to Canadian or 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 Athabasca has a 30-year transportation arrangement with Suncor Energy Inc., the initial shipper on the pipeline. The Athabasca System is regulated by the Alberta Energy and Utilities Board (the EUB).

CCPS was acquired by the Issuer in September 2003. It has a capacity of 300,000 barrels per day, including 4.3 million barrels of tankage, and extends approximately 650 miles from Chicago, Illinois to Cushing, Oklahoma. CCPS has historically operated a south-to-north service, but the Issuer intends to reverse the flow of this system in order to transport Canadian crude south by the end of 2004. Reversal of the line is dependent upon acceptance of proposed tolling arrangements by Canadian producers and regulatory approval. The reversed line would be renamed the Spearhead Pipeline.

The Frontier System is owned by Frontier Pipeline Company, a Wyoming general partnership owned 77.8% by the Issuer. This pipeline consists of 290 miles of 16-inch pipeline running from Wyoming to the northeast border of Utah, for ultimate delivery into the Salt Lake City refining market. The Frontier System has a capacity of 62,200 barrels per day and total deliveries averaged 41,700 barrels per day in 2003. The Frontier System is regulated by the Federal Energy Regulatory Commission (FERC).

The Mustang System is owned and operated by Mustang Pipe Line Company, a Delaware general partnership, owned 30% by the Issuer. This pipeline consists of 215 miles of 18-inch line with a capacity of 100,000 barrels per day. Total deliveries averaged 50,200 barrels per day in 2003. The Mustang System receives crude oil from the Lakehead System in the Chicago, Illinois area and delivers to the Patoka, Illinois area. The Mustang System is regulated by the FERC.

The Chicap System is owned and operated by Chicap Pipe Line Company, a Delaware corporation, owned 23% by the Issuer. This pipeline consists of 205 miles of 26-inch line with a capacity of 360,000 barrels per day. The pipeline transports crude oil from the Patoka pipeline hub to the Chicago, Illinois area. Total deliveries averaged approximately 221,700 barrels per day in 2003. The Chicap System is regulated by the FERC.

The Toledo System is owned and operated the Issuer. This pipeline consists of 35 miles of 16-inch line and connects the Lakehead System at Stockbridge, Michigan to two refineries in the Toledo, Ohio area. The pipeline has a capacity of 80,000 barrels per day of heavy crude oil and total deliveries averaged 63,400 barrels per day in 2003. The Toledo System is regulated by the FERC.

Enbridge System

Properties

The Enbridge System (including Terrace Phase III) consists of approximately 4,950 miles of pipe with diameters ranging from 12 inches to 48 inches, 33 main line pump station locations with a total of approximately 980,000 installed horsepower and 104 tanks with an aggregate capacity of approximately 14.8 million barrels. Linefill required for operation amounts to approximately 18.5 million barrels, all of which is owned by the shippers on the Enbridge System. 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, NGL and refined products.

The Enbridge System consists of a number of separate segments:

(i) a Western Canadian segment that consists of five pipelines, ranging in diameter from 16-48", 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 20-inch lines from Sarnia to the Toronto area, with a capacity of 150,000 barrels per day. The Sarnia to Toronto segment includes lateral lines (ranging from 12 to 20 inches) from Westover, Ontario, to Nanticoke, Ontario and Niagara Falls, Ontario.

(iii) a Montreal, Quebec to Sarnia, Ontario segment, Line 9, which consists of a 30-inch line with a capacity of 240,000 barrels per day.

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

Title to Properties

In general, the Enbridge System is located on land owned by others and operated under perpetual easements or rights of way granted by the owners. Enbridge Pipelines Inc. (Enbridge Pipelines) has the right under the National Energy Board Act (the NEB Act) to apply to the NEB for an immediate right to enter any land and has exercised this right from time to time as required. In addition, the NEB Act provides for the approval of the crossing by interprovincial pipelines of roads, highways and other utilities. Approval for the crossing of railways and rivers by the pipeline is obtained from railways and public authorities, respectively. The pumping stations, terminals and certain other facilities are located on land owned by Enbridge Pipelines.

Terrace Expansion Project

The Terrace Expansion Project, which was undertaken by the Issuer and the Partnership, was a phased expansion that has provided an additional net 350,000 barrels per day of capacity for western Canadian crude oil producers seeking greater access to U.S. Midwest markets. Phase I was completed in 1999 and provided additional heavy crude oil capacity of 170,000 barrels per day. The first phase of the expansion included construction of a new 36-inch diameter pipeline and related facilities from Kerrobert, Saskatchewan to Clearbrook, Minnesota. The new pipeline construction joined existing 48-inch pipeline loops between Kerrobert and Clearbrook, creating another separate pipeline joining those locations. Phase I cost $610 million in Canada and US$145 million was spent by the Partnership in the United States. Phase II was completed in 2002 and included the extension of the 36-inch pipeline on the Enbridge System between Hardisty and Kerrobert. Phase II added 40,000 barrels per day of incremental capacity to the Enbridge System at a cost of approximately $100 million.

Phase III was completed in 2003 and included an extension of the 36-inch pipeline on the Lakehead System between Clearbrook, Minnesota and Superior, Wisconsin and pumping additions in both Canada and the U.S. This phase added 140,000 barrels per day of incremental capacity at a cost of approximately $120 million on the Enbridge System and approximately US$193 million on the Lakehead System.

Regulation

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 accounting and rates of such pipelines. Prior to 1995, Enbridge System tolls were regulated under a method called "cost-of-service ratemaking", which uses the historical cost of property, plant and equipment, less depreciation and deferred income taxes in setting the rate base. Under this method, the Issuer was allowed, though not guaranteed, the opportunity to recover its investment in pipeline facilities and to earn a return on rate base. Tolls were

approved by the NEB based on the estimated costs of operating the pipeline, projections of system deliveries, rate base and an allowed rate of return.

In February 1995, Enbridge Pipelines filed a toll settlement negotiated with the Canadian Association of Petroleum Producers (CAPP), which incorporated a methodology of determining tolls based on an incentive approach. Specific parameters were agreed upon to calculate tolls through 1999. The main objective of this methodology was to more closely align the interests of the Issuer with the interests of its shippers. The Incentive Tolling Agreement provides for the sharing with customers the results of operating efficiencies and cost savings achieved above certain thresholds on an annual basis. Enbridge reached an agreement with CAPP for the continuation of certain incentive parameters for 2000 through 2004 (the Incentive Tolling Settlement). The Issuer expects that negotiations for a renewed agreement will be completed in 2004.

The incentive toll model incorporates several mechanisms that protect the earnings of the Enbridge System. In addition to safeguards from volume fluctuations beyond the Issuer's control, the toll structure contains adjustment provisions to incorporate cost increases resulting from occurrences such as new safety and environmental legislation, certain expenses associated with maintaining the integrity of the pipeline, and new or expanded services requested by industry. In addition, the agreement provides for the recovery of actual income taxes and an allowance for oil losses. In general terms, the Incentive Tolling Settlement ensures that the Issuer is not at risk in the short-term for changes in crude oil production, but will benefit on a shared basis from its efforts to increase effective system utilization and operate more efficiently.

Tariffs

Under published tariffs for the Enbridge System, the tolls for transportation, including terminalling and tankage charges where applicable, of light crude oil from Edmonton to principal delivery points, at December 31, 2003, are set forth below.

	Canadian Toll Per Barrel
	(Cdn dollars)
Regina, Saskatchewan	$ 0.870
U.S. border near Gretna, Manitoba	$ 1.091
Sarnia, Ontario	$ 1.269

The rates for medium and heavy crude oils are higher, while those for refined products and natural gas liquids (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. Enbridge plans to file new tolls with the NEB on April 1, 2004 to reflect provisions in the Incentive Tolling Settlement, the SEP II Risk Sharing Agreement and the Terrace Agreement.

SEP II Risk Sharing Agreement

The Issuer, EEP and CAPP entered into a Risk Sharing Agreement, effective for 15 years, with respect to SEP II, a 100,000 barrels per day 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 will result in a greater return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. During 2003, the Issuer and EEP were allowed to earn the minimum rate of return on SEP II.

Terrace Agreement Toll Surcharge

As part of the Terrace Agreement, the Issuer, 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 the Issuer and EEP. The toll surcharge is also subject to increase or decrease in certain defined circumstances.

Sources of Shipments

Shipments tendered 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.

Deliveries

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 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; Toledo, Ohio; and Buffalo, New York.

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, 2003.

	Deliveries		
(thousands of barrels per day)	**2003**	**2002**	**2001**
Prairie Provinces			
Light crude oil	**176**	170	158
Medium and heavy crude oil	**91**	73	76
Refined products	**83**	81	76
	350	324	310
United States			
Light crude oil	**252**	286	273
Medium and heavy crude oil	**690**	601	631
Natural gas liquids	**4**	6	5
	946	893	909
Ontario			
Light crude oil	**391**	380	391
Medium and heavy crude oil	**68**	78	78
Natural gas liquids	**109**	111	104
	568	569	573
	1,864	1,786	1,792
Barrel Miles (billions)	**361**	351	350
Average Haul (miles)	**530**	539	535

Enbridge System average deliveries include Line 9 volumes of 216,000 barrels per day (2002 – 204,000; 2001 – 217,000).

Safety and Environment

The Issuer has appropriate mechanisms in place to monitor and address the safety and environmental aspects of its operation. The Issuer has health, safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. These systems promote awareness and foster openness and dialogue with employees, the public, regulators and key stakeholders, resulting in a positive safety and environmental image, and improved safety and environmental performance throughout the Issuer's pipeline operations and in the communities in which it operates.

The Issuer seeks to ensure compliance with all applicable regulatory and permit requirements. The Issuer acts to identify, evaluate and mitigate any potential impacts and issues associated with its operations. It also engages in a concerted effort to reduce environmental liabilities associated with oil contaminated soil.

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

In response to increased awareness of the climate change issue, Enbridge has established a Climate Change Task Force. This task force reviews business and environmental risks associated with climate change and identifies policies and actions to mitigate this risk. No material risks have been identified to date. Following Canada's ratification of the Kyoto Protocol, the Company has continued to assess the potential impact on oil sands investment. Moody's Investor Services recently surveyed oil sands operators and concluded that Kyoto is expected to have a minimal effect on the development of Alberta's oil sands resource. The Company is encouraged by this conclusion as it lends support for the sustainability of supply for its liquids pipelines.

None of the environmental protection requirements applicable to the pipeline operations of the Issuer 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 reviews and audits are conducted to assess compliance with legislation and company policy. The Issuer consistently has been an industry leader in safety and environment and has received numerous industry awards. To the best of the Issuer'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 2003, 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 optimized.

Employees

The Issuer employs approximately 810 individuals in its Liquids Pipelines operations.

GAS PIPELINES

Gas Pipelines includes proportionately consolidated investments in transmission pipelines that transport natural gas.

The Alliance Pipeline is a natural gas pipeline extending 1,860 miles from supply areas in northwestern Alberta and northeastern British Columbia to Chicago, Illinois. The pipeline commenced service in December 2000 and has a firm delivery capacity of approximately 1.3 bcf of natural gas per day, the majority of which is committed through transportation agreements. The Issuer holds a 50.0% interest in, and jointly controls, the U.S. portion of the Alliance Pipeline with Fort Chicago Energy Partners L.P.

The Issuer holds a 60% investment in, and provides operating services to, the Vector Pipeline, which transports natural gas from Chicago, Illinois to Dawn, Ontario. The Vector Pipeline extends 344 miles and connects with the Alliance Pipeline and other natural gas transmission systems, all providing a transportation link for western Canadian gas supplies. The Vector Pipeline commenced service in December 2000 and has a delivery capacity of 1.0 bcf of natural gas per day.

The Issuer has contracted for 105 million and 260 million cubic feet per day of the capacity available on the Alliance and Vector pipelines, respectively, of which a substantial portion is committed to satisfy Enbridge Gas' delivery requirements.

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 Issuer's knowledge, the operations of all affiliated systems are in substantial compliance with applicable environmental and safety regulations.

SPONSORED INVESTMENTS

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P., Enbridge Energy Management, L.L.C. and Enbridge Income Fund. 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. From May 2001 to October 2002, the Company, through its subsidiary, Enbridge Pipelines Inc., owned 100% of Enbridge Midcoast Energy, which is now a wholly owned subsidiary of EEP. EIF is a publicly traded income fund whose primary operations include a 50% interest in Alliance Pipeline Canada and a 100% interest in a crude oil and liquids pipeline and gathering system located in southeastern Saskatchewan and southwestern Manitoba. The business activities of Sponsored Investments are carried out in the United States through the Partnership, and in Canada through EIF.

The Company owns an effective 12.2% equity investment in the Partnership. The Partnership transports crude oil and other liquid hydrocarbons through a common carrier pipeline and transports, gathers, processes and markets natural gas and natural gas liquids.

The Partnership owns the Lakehead System, which consists of approximately 3,300 miles of pipe extending from the Canadian border near Neche, North Dakota, where it connects with the Enbridge System, to Superior, Wisconsin, where it splits into two branches. One branch travels through the upper Great Lakes region and the other though the lower Great Lakes region of the Unites States. Both branches re-enter Canada near Marysville, Michigan where they reconnect with the Enbridge System.

The Partnership also owns Enbridge Midcoast Energy, purchased from the Company in October 2002. Enbridge Midcoast Energy transports, gathers, processes and markets natural gas and natural gas liquids in the Gulf Coast and mid-continent areas of the United States.

In December 2001, the Partnership acquired the East Texas System, which includes approximately 2,000 miles of natural gas gathering and transmission pipelines, four natural gas treating plants, two of which are active currently, and three natural gas processing plants, two of which are active currently.

On December 22, 2003, the Issuer announced the acquisition of several assets from Shell Pipeline Company LP and Shell Oil Products U.S. The majority of the assets, located at or originating from Cushing, Oklahoma, and consisting of two different pipelines and two crude oil storage terminals, are to be acquired by EEP for approximate consideration of US$115 million. Closing of this acquisition is anticipated to occur in the first quarter of 2004, subject to regulatory approvals and rights of first refusal.

On December 31, 2003, EEP acquired natural gas gathering and processing assets in north Texas. The gathering system, referred to as the North Texas system, primarily serves the Fort Worth Basin, including the Barnett Shale producing zone, and is complementary to the Partnership's existing natural gas systems in the area. The assets were purchased for cash of US$249.7 million.

The Issuer created EIF in June 2003. On formation, the Issuer sold to EIF its 50% interest in the Canadian segment of the Alliance Pipeline, as well as its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. The Issuer acts as EIF's sponsor and manager, and holds a 41.9% interest in EIF in the form of subordinated trust units of EIF, and preferred units of Enbridge Commercial Trust, a direct subsidiary of EIF.

Employees

The Issuer employs approximately 1,050 individuals who provide services only to its Sponsored Investments business segment.

Each of Enbridge Energy Partners, L.P. and Enbridge Energy Management, L.L.C. has filed an Annual Report on Form 10-K for the year ended December 31, 2003 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 either Form 10-K is intended to be incorporated by reference in this Renewal Annual Information Form of Enbridge Inc.

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, as well as gas services operations, including the Company's proportionately consolidated investment in Aux Sable and natural gas gathering and processing operations through an equity investment in AltaGas Services Inc.

The Issuer's gas distribution business is conducted primarily through Enbridge Gas, a wholly-owned subsidiary. Enbridge Gas is Canada's largest natural gas distribution utility, serving over 1.7 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. In addition, Enbridge Gas, through its wholly-owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence), serves Massena, Ogdensburg, Potsdam and surrounding areas in northern New York State. Consistent with the quarter lag basis of consolidation as described in Note 1 to the Issuer's Consolidated Financial Statements, the operating and financial information of Enbridge Gas represent September 30 fiscal year end results.

The gas distribution utility business of Enbridge Gas is regulated by the Ontario Energy Board (the OEB), its principal regulator, which regulates various aspects of the Issuer's utility operations in Ontario. Similar regulations apply to St. Lawrence under the New York State Public Service Commission. Gazifère is regulated under La Regie de L'energie in Quebec and Enbridge Gas New Brunswick is regulated by the New Brunswick Public Utilities Board.

ENBRIDGE GAS

Description of Business

Distribution Service

Enbridge Gas' 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 basis (i.e., non-contract). 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, Enbridge Gas 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 Enbridge Gas 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 the Enbridge Gas supply portfolio (system supply). Alternatively, a gas user 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 the gas at a TransCanada receipt point in western Canada or at a TransCanada delivery point in Ontario, and the Company 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 Enbridge Gas at a TransCanada receipt point in western Canada. Enbridge Gas, 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. Since the commodity cost of gas is flowed through to customers with no mark up, the customer's choice of gas supply has no effect on earnings.

Gas Supply

To acquire the necessary volume of gas to service its customers, the Company maintains a diversified gas supply portfolio. During 2003, Enbridge Gas acquired approximately 182 bcf of natural gas, of which 41.5% was under long-term contracts with independent western Canadian producers. The remaining 58.5% was purchased through short-term or monthly spot purchases. Enbridge Gas also transported 296 bcf of natural gas on behalf of direct purchase customers operating under a transportation service arrangement.

Enbridge Gas' 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-based prices or the differential between such prices and prices based on the New York Mercantile Exchange. Enbridge Gas has undertaken, on behalf of its customers, a natural gas price risk management program to manage the price volatility of its forecasted system supply gas.

Enbridge Gas supports the concept of direct purchase by its customers; however, there are security of supply, operational and consumer protection issues associated with this option. Therefore, all of Enbridge Gas' long-term supply contracts with independent western Canadian producers or marketers allow for reductions in contract volumes to accommodate customers who pursue direct purchase arrangements for the first time.

Transportation

Enbridge Gas relies primarily upon TransCanada for transportation service to bring its diversified gas supply from western Canada to its franchise area. Enbridge Gas has long-term firm transportation service contracts with TransCanada, over varying time periods, for annual deliveries of approximately 311 bcf of natural gas. This includes deliveries by direct purchase customers via TransCanada capacity that has been assigned by Enbridge Gas 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 Enbridge Gas flexibility in obtaining its own gas supply and accommodating the transportation of natural gas purchased directly by end-use customers.

TransCanada's transportation tolls, which are approved by the NEB, consist of a fixed cost (demand component) and a variable cost (commodity component). The demand component must be paid regardless of the volume transported except to the extent that Enbridge Gas has negotiated the right to turn back a certain amount of unused capacity to TransCanada. Enbridge Gas allows customers to turn back capacity up to the amount that can be turned back by Enbridge Gas to TransCanada. This enabled Enbridge Gas to avoid paying for unused capacity during 2003. In 2004, Enbridge Gas Distribution does not expect to incur any charges for unused capacity.

While Enbridge Gas continues to place great reliance on western Canadian supplies and pipeline transportation systems, efforts have been directed towards acquiring U.S. supply and alternative pipeline capacity directly into Ontario. Enbridge Gas has entered into contracts for firm transportation service on the Alliance and Vector pipelines, which began operations in fiscal 2001. Enbridge Gas also has long-term contracted capacity on the St. Clair Pipeline, which interconnects with the facilities of Union Gas Limited (Union) and Michigan Consolidated Gas Company (MichCon), as well as access to U.S. gas supplies throughout the Union system near Windsor, Ontario and at Dawn by the Vector Pipeline. In addition, Enbridge Gas has contracted with Niagara Gas for long-term capacity on the Link Pipeline, which interconnects the facilities of Enbridge Gas with ANR Pipelines Company (ANR) and MichCon.

Gas Storage

The business of Enbridge Gas 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 Enbridge Gas to take delivery of gas on favourable terms during off-peak periods for subsequent use during the winter heating season. This practice permits Enbridge Gas 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 to Enbridge Gas' franchise area.

Enbridge Gas' principal storage facilities are located in southwestern Ontario near Dawn and have a total working capacity of approximately 99 bcf. Approximately 92 bcf of the total working capacity is available to Enbridge Gas with the remaining capacity contracted to third parties. In addition, Enbridge Gas has a long-term storage contract with Union for 20 bcf of storage capacity.

The Enbridge Gas storage facilities are connected to the Dawn storage and transmission hub by two 30-inch pipelines and a 16-inch pipeline owned by Enbridge Gas. 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, from there, transported to Enbridge Gas' major market area in the greater Toronto area through the transmission facilities of Union. Enbridge Gas has transportation contracts with TransCanada, Vector and Union for the delivery of gas to and from storage.

Properties

At the end of its 2003 fiscal year, Enbridge Gas owned and operated approximately 19,513 miles of mains (2002 – 19,010 miles) for the transportation and distribution of gas, as well as the service pipes to transfer gas from mains to meters on the customers' premises. In addition, Enbridge Gas owns equipment and other properties used for offices, warehouses, metering and regulating stations and service shops.

Regulation

Recent changes in regulation reflect a trend in North America toward incentive or performance-based regulation (PBR). Enbridge Gas operated under an OEB-approved targeted PBR plan for a three-year term, which concluded in fiscal year 2002. The PBR plan used a formula to calculate the level of operation and maintenance costs recoverable in rates. The formula included escalation factors for customer growth and inflation, which were offset by an annual productivity credit of 1.1%. The PBR plan also allowed for the recognition, subject to OEB approval, of factors impacting operation and maintenance costs that were outside of management's control. During the PBR period, Enbridge Gas was allowed to retain the savings if it achieved lower operation and maintenance expenses than those calculated under the formula.

The key elements in the OEB rate application for fiscal 2004 and rate decisions for 2003 and 2002 are summarized as follows.

	2004	2003		2002	
	Requested[1]	Approved	Requested	Approved	Requested
Rate base (Cdn $millions)		3,156	3,226	3,019	3,114
Rate of return on rate base		8.32%	8.32%	8.26%	9.32%
Deemed common equity component of total capital structure		35.00%	35.00%	35.00%	35.00%
Rate of return on common equity		9.69%	9.69%	9.66%	11.38%

1. EGD's 2004 rate application requested that rates for 2004 be set by increasing 2003 rates by 90% of the forecast Ontario Consumer Price Index, that being an increase of 1.8%. As such, the typical rate base and rate of return related information would not be applicable to 2004 rates.

2004 Fiscal Year

Enbridge Gas filed its fiscal 2004 rate application with the OEB in April 2003. Enbridge Gas' objective was to return to a regulatory schedule whereby rates would be set prospectively. The 2004 rate application requested that rates for 2004 be set by increasing 2003 rates by 90 percent of the forecast Ontario Consumer Price Index, that being an increase of 1.8 percent. No adjustment was required to the 2004 rates.

On November 7, 2003, the OEB issued its Decision with Reasons in respect of Enbridge Gas' 2003 rate application (Decision).

The OEB accepted the negotiated settlement proposal for Enbridge Gas' fiscal 2004 rates on September 4, 2003, thus allowing rates to be in place for the start of the 2004 fiscal year. The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a normalized basis exceed the benchmark return on equity (ROE), these excess earnings would be shared on a 50/50 basis between ratepayers and Enbridge Gas' shareholder.

In September 2003, the OEB completed a generic hearing (Enbridge and Union Gas were co-applicants) to review and consider possible revisions to the current formula that is based on the long-term Canadian bond yield, which is used to set the utility's rate of return. A decision was issued on January 16, 2004, which dismissed the application and confirmed the use of the existing formula. A return on equity of 9.69% is embedded in 2004 rates.

2003 Fiscal Year

In September 2002, Enbridge Gas filed its fiscal 2003 rate application with the OEB. In March 2003, as a result of settlement negotiations with intervenors, an agreement was reached on the majority of the financial aspects affecting rates, such that rates could be set on an interim basis. Interim rate increases, reflecting a revenue deficiency of $38.2 million, were implemented beginning in May 2003. Enbridge Gas'

2003 rates remained preliminary until the OEB's Decision with Reasons (Decision) was issued on November 7, 2003, with respect to outsourcing of its customer care, gas supply and gas control functions in prior years. In its Decision, the OEB disallowed the recovery of a portion of customer care costs from ratepayers relating to the 2003 and 2004 fiscal years. The full impact of the decision was recorded in the first quarter of fiscal 2004 for Enbridge Gas, resulting in a $14.1 million ($9.1 million after tax) reduction in earnings.

The 2003 rate application also included a request to review and revise the current formula used to calculate the rate of return on common equity. This request was heard in a separate phase of the 2003 rate hearing. The increase in the requested rate of return from 9.69% to 11.50% reflected Enbridge Gas' need to compete for investment dollars in the North American marketplace.

2002 Fiscal Year

In fiscal 2002, Enbridge Gas moved to a quarterly review of rates in order to ensure that gas commodity prices recovered in rates more closely reflect market conditions. As Enbridge Gas does not mark up the cost of the gas commodity, increases or decreases in rates during a fiscal year are due to fluctuations in the market price of natural gas.

Final rates, reflecting a revenue deficiency of $9.2 million, were implemented effective August 1, 2002.

Gas Distribution Access Rule

In December 2002, the OEB issued the Gas Distribution Access Rule (GDAR). The purpose of GDAR is to establish rules governing natural gas distributors' conduct in relation to gas marketers and establish conditions of access to gas distribution services. As Enbridge Gas does not accept that the OEB has jurisdiction to impose billing options on Enbridge Gas, an appeal was filed with the Divisional Court of Appeal in January 2003. The appeal states that the GDAR discriminates against gas distributors in favour of gas vendors, creates a contractual model that improperly provides for gas vendors rather than gas distributors to provide distribution services to consumers and improperly regulates billing services.

In September 2003, the Ontario Divisional Court issued a decision dismissing the appeals and upholding the OEB's jurisdiction to enact the billing portions of the GDAR. Both the Company and Union Gas Limited have sought leave from the Ontario Court of Appeal to hear an appeal of the decision.

In the interim, the Company is working closely with the OEB and gas marketers to resolve outstanding GDAR implementation issues.

Undertakings

The Issuer and Enbridge Gas have entered into undertakings with the Government of Ontario committing the Issuer and Enbridge Gas to certain obligations relating to the maintenance of common equity, as well as a restriction on diversification to the effect that Enbridge Gas must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage, or transmission of gas, without the OEB's prior approval.

In compliance with these undertakings, Enbridge Gas applied to the OEB and has received approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and the Gas Sales and Oil Production activities.

Affiliate Relationships Code

Enbridge Gas is subject to the provisions of the Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between gas distributors, transmitters and storage companies and their respective affiliate companies. It is intended to minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities; protect the confidentiality of consumer information collected in the course of providing utility services; and ensure there is no preferential access to regulated utility services. The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service level agreements must be prepared and transfer pricing guidelines.

Price Advantage of Natural Gas

Natural gas is the predominant energy form in the residential heating market throughout Enbridge Gas' franchise area. In 2003, over 50% of Enbridge Gas' distribution revenues resulted from natural gas sales to the residential market. The primary competition to natural gas in the residential market has historically been from domestic fuel oil and electricity. For the twelve months ended September 30, 2003, natural gas enjoyed, on average, a price advantage on an equivalent annual volume basis of about 37% against electricity and 20% against domestic fuel oil.

Despite recent increases in the price of natural gas, Enbridge Gas expects that natural gas will continue to hold a price advantage over electricity in its franchise area and maintain its competitive advantage against domestic fuel oil in the residential heating market. Enbridge Gas' commercial and industrial distribution volume is exposed to the risk of customers switching to an alternate fuel, to the extent they have that ability. However, the customer's ability to fuel switch requires a long-term decision and a potentially significant capital investment, thus reducing the risk of long-term decreases in natural gas demand due to short-term price competitiveness.

Energy Efficiency

Enbridge Gas maintains a prominent profile in the communities it serves and uses this to effectively communicate the benefits and opportunities associated with responsible energy conservation. The OEB requires that gas distribution companies support demand side management (DSM) programs on behalf of all customer groups. Since the mid-1990s, Enbridge Gas has employed an energy conservation strategy in the design of its marketing programs. Through its DSM program, Enbridge Gas not only promotes the use of natural gas as an environmentally preferred fuel, but also develops and delivers energy efficiency and conservation programs, which enable customers to optimize their energy usage.

Enbridge Gas has negotiated a regulatory arrangement that awards it a financial incentive when it exceeds its energy efficiency targets. This is in addition to the cost recovery and lost revenue adjustment mechanisms that were already in place to hold Enbridge Gas harmless from the costs of supporting DSM.

Historical Operating Statistics for Enbridge Gas

Year ended September 30,	2003	2002	2001
Gas supply and sendout (mmcf) [1]			
Natural gas purchased	**181,671**	117,376	186,873
Gas into storage	**(117,831)**	(51,508)	(113,598)
Gas out of storage	**101,615**	63,033	112,320
Total gas sendout	**165,455**	128,901	185,595
Gas sales to customers (mmcf) [1]			
Residential	**95,751**	74,132	99,595
Commercial	**53,076**	42,531	63,323
Industrial	**9,400**	8,352	18,056
Wholesale	**4,241**	3,523	1,387
Total sales	**162,468**	128,538	182,361
Used by Enbridge Gas (mmcf) [1]	**219**	226	311
Other (mmcf) [1]	**2,768**	137	2,923
	165,455	128,901	185,595
Transportation of gas (mmcf) [1]	**295,775**	281,416	243,125
Total sales and transportation of gas (mmcf) [1]	**458,243**	409,954	425,486
Degree day deficiency [2]			
Actual	**4,029**	3,362	3,743
Forecast based on normal weather	**3,565**	3,700	3,816
Number of active customers – year end [3]	**1,652,372**	1,597,579	1,546,255
Average use per residential customer (mcf) [1]	**109**	97	130
Number of employees – year end	**1,600**	1,585	1,563
Miles of mains in use – year end	**19,513**	19,010	18,173

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 October 1 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 Enbridge Gas' earnings.

Safety and Environment

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 relationship of these emissions to potential global climate change and poor local air quality is currently under study by research organizations and governments. The use of fossil fuels results in emissions of carbon dioxide, sulphur dioxide, nitrogen oxides, total suspended particulates, carbon monoxide, volatile organic compounds and methane. However, the levels of these emissions are not the same for all fossil fuel types. Natural gas is the cleanest burning fossil fuel, releasing significantly lower emissions than those arising from oil or coal.

Methane, the principal component of natural gas, is a "greenhouse gas". Scientists are concerned that increases in greenhouse gas compositions of the atmosphere could lead to global climate change. Although some 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. The Canadian Gas Association estimates that releases of methane average about 1.13% of total Canadian natural gas production from wellhead to burner tip. Leak detection studies are ongoing to identify potential sources of methane emissions in the distribution of natural gas and to identify specific measures that can be taken to reduce these emissions.

Enbridge Gas is committed to participating in Canada's Voluntary Climate Change Challenge and Registry Program, and has been recognized by that organization for its leadership. Enbridge Gas has implemented measures to reduce methane emissions from its distribution system, lower the energy used in its daily business activities, encourage customer participation in Enbridge Gas' energy efficiency and conservation programs, and to promote fuel-switching to natural gas from more polluting fuels. Each of these measures moves Enbridge Gas closer to the realization of its emission reduction targets, despite the pressures of significant growth in its customer base. These initiatives have been documented (in conjunction with Enbridge Inc.) in annual "Action Plans" submitted to VCR Inc., the entity that manages the Voluntary Climate Change Registry.

Programs have been implemented to ensure adherence to the Issuer'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 Enbridge Gas are expected to adversely affect its competitive position, capital expenditure program or level of earnings.

Employees

At September 30, 2003, Enbridge Gas had 1,600 employees, 44% of whom are unionized and the majority of which are represented by the Communications, Energy and Paperworkers Union, Local 975. The current negotiated collective agreement expired on December 31, 2003. The Company reached a tentative settlement with representatives of its union in early December 2003 for a 3-year collective agreement. The settlement was ratified in January 2004.

Enbridge Gas has filed a Renewal Annual Information Form for the year ended September 30, 2003 with the Canadian Securities Regulatory Authorities. This document contains detailed disclosure about Enbridge Gas and is publicly available through www.sedar.com. No part of Enbridge Gas' Renewal Annual Information Form is intended to be incorporated by reference in this Renewal Annual Information Form of Enbridge Inc.

OTHER GAS DISTRIBUTION AND SERVICES BUSINESSES

Other businesses in the Gas Distribution and Services segment include Enbridge Gas Services, Gazifère Inc., Niagara Gas Transmission Ltd. (Niagara Gas), Tidal Energy Marketing, CustomerWorks LP, and ownership interests in Noverco, Enbridge Gas New Brunswick, AltaGas Services, Aux Sable, Sunbridge, and Inuvik Gas. Gazifère is a gas distribution utility located in southwestern Quebec. Niagara Gas provides transmission services to Enbridge Gas, Gazifère, St. Lawrence and MichCon. Enbridge Gas Services manages the Company's merchant capacity commitments on the Alliance and Vector pipelines.

Enbridge Commercial Services Inc., a wholly owned subsidiary, commenced operations on January 1, 2000 to provide information technology, fleet services, call management centre, customer care and billing services to Enbridge Gas and others. In 2001, Enbridge and BC Gas Inc. formed a new entity, CustomerWorks LP, to provide service covering the entire meter-to-cash process, including many of the services provided by Enbridge Commercial Services. Operations commenced January 1, 2002. CustomerWorks provides services to more than 2.4 million customers including customers of BC Gas Utility and Enbridge Gas. 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 preference shares. Noverco is a holding company that owns a 77% interest in Gaz Metropolitain, a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metropolitain has a 50% interest in TQM Pipeline, a pipeline transporting natural gas in Quebec.

The Company owns 63% of and operates Enbridge Gas New Brunswick (EGNB), the natural gas distribution franchise in the province of New Brunswick. EGNB constructed a new distribution system and has approximately 2,500 customers. Over 310 kilometres (193 miles) of distribution main has been installed with the capability of attaching approximately 9,300 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

The Issuer holds a 40.3% interest in AltaGas Services Inc., a company engaged in midstream natural gas activities, including distribution and energy services, natural gas and natural gas liquids marketing, and the wholesale marketing of power.

The Issuer 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.

The Issuer performs liquids marketing activities through its ownership of Tidal Energy Marketing Inc. and is a partner in the SunBridge wind power project. In January 2002, the Company entered into a strategic alliance to facilitate the development of heavy oil upgrading technology. These activities require limited capital and are not expected to provide significant returns in the near term.

The Company also holds a 33.3% interest in the Inuvik Gas project, a 30-mile gas pipeline and a local distribution network that supplies natural gas to the Town of Inuvik in the Northwest Territories. This project represents the first commercialization of Mackenzie Delta natural gas reserves and augments the Issuer's experience with construction of pipelines in permafrost conditions. It also provided a successful model for cooperation with local interests in the development of energy delivery infrastructure.

Employees

The Issuer employs approximately 170 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, CLH, a 24.7% investment in the Colombian crude oil pipeline, Ocensa, and a 100% interest in CITCol, which is responsible for operating the Ocensa pipeline. The Company holds a 45% interest in the SWEC Partnership that previously operated the Jose Terminal in Venezuela.

CLH is Spain's largest refined products transportation and storage business. CLH operations include a 2,100-mile pipeline distribution network and storage facilities with capacity of approximately 40 million barrels. The pipeline network links Spanish refineries with the principal areas of consumption. CLH's transportation capability is enhanced through the operation of a fleet of tanker trucks and ships.

The Ocensa pipeline consists of 515 miles of 30-inch and 36-inch pipeline, pumping units, tankage and marine loading facilities, with a capacity to transport 550,000 barrels per day 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.

The Jose Terminal is part of a large petroleum and petrochemical complex in Venezuela and handles crude oil from eastern Venezuelan fields for loading into tankers for export. As a result of breaches of the Jose Terminal operating agreement by PDVSA, the Venezuelan state oil company, the SWEC Partnership has filed for international arbitration, as provided for in the operating agreement. The company ceased recognition of earnings commencing February 1, 2003.

Through Enbridge Technology Inc. (Enbridge Technology), the Issuer offers technology solutions for liquid hydrocarbon pipelines and natural gas transmission and distribution companies around the world. In addition to pipeline operator training services, Enbridge Technology offers advisory, technology transfer, engineering and contract operations services.

The international operations of the Issuer are subject to federal, state or local laws and regulations relating to environmental protection and operational safety. To the best of the Issuer'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

The Issuer's International operations directly employ approximately 30 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 are 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.

Employees

The Issuer's corporate activities and operations employ approximately 130 individuals.

ITEM 5

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, 2003, which are incorporated herein by reference (the page references below are to the Company's 2003 Annual Report):

Liquids Pipelines – Business Risks (pages 21 to 22);
Gas Pipelines – Business Risks (page 24);
Sponsored Investments – Business Risks (page 27);
Gas Distribution and Services – Business Risks (pages 32 to 33);
International – Business Risks (page 35).

ITEM 6

DIVIDENDS

DIVIDENDS PAID

(Canadian dollars per share)	2003	2002	2001
Preference Shares, Series A	**1.375**	1.375	1.375
Common Shares	**1.660**	1.520	1.400

Dividends on common shares are paid quarterly as determined by the Company's Board of Directors. The Company's common share dividend in recent years has been in a range of 50-60% of normalized earnings and, subject to Board approval, is expected to continue in this range. 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.

ITEM 7

DESCRIPTION OF CAPITAL STRUCTURE

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

At December 31, 2003, the Company's capital structure consists of 171.9 million common shares with a book value of $2,239.9 million, 5.0 million preference shares, Series A with a book value of $125.0 million and $532.4 million in preferred securities.

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 at all such meetings of shareholders for each share held.

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 bid 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 or announcement 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 5,000,000 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. Subsequent to December 31, 2003, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $26.00 per share if redeemed on or prior to December 1, 2004; $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.

Preferred Securities

The Company has $175.0 million of 7.6%, $200 million of 7.8%, and $175.0 million of 8.0% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option at par value plus all accrued and unpaid distributions to the redemption date, in whole or in part, after the fifth anniversary of each issue and have no stated maturity date. Both the 7.6% and the 8.0% Preferred Securities were issued during 1999 and therefore may be redeemed in 2004. The 7.8% Preferred Securities were issued during 2002 and therefore may be redeemed in 2007. 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.

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 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.

ITEM 8

MARKET FOR SECURITIES

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

		TSX (C$)					NYSE (US$)
		ENB	ENB.PR.A	ENB.PR.B	ENB.PR.C	ENB.PR.D	ENB
January	High	44.33	26.00	26.25	26.50	26.89	28.71
	Low	41.85	24.90	25.75	26.00	26.15	27.20
31-Jan	Close	42.50	25.16	25.77	26.16	26.50	27.74
	Volume	6,090,600	170,300	99,900	98,800	124,700	575,200
February	High	42.60	25.51	25.90	26.58	27.00	28.61
	Low	40.95	24.35	25.30	26.05	26.25	26.90
28-Feb	Close	42.50	24.85	25.76	26.31	26.79	28.53
	Volume	6,020,600	271,800	99,700	58,300	87,000	398,600
March	High	44.32	25.00	25.95	26.60	26.93	30.02
	Low	42.00	24.25	25.02	25.50	25.29	28.25
31-Mar	Close	43.94	24.35	25.30	25.55	25.90	29.80
	Volume	6,840,300	42,900	129,100	64,700	189,800	362,400
April	High	44.40	25.44	25.80	26.34	26.78	30.50
	Low	42.71	23.77	25.11	25.53	25.70	29.45
30-Apr	Close	43.65	25.44	25.65	26.34	26.35	30.40
	Volume	5,647,900	54,500	86,900	69,900	155,200	186,800
May	High	47.90	25.81	26.60	27.00	27.47	35.01
	Low	43.35	24.91	25.55	25.91	26.40	30.52
30-May	Close	46.77	25.68	26.20	26.47	27.20	34.13
	Volume	6,103,200	72,200	98,300	81,300	181,100	407,800
June	High	49.30	26.23	26.60	27.00	27.74	36.76
	Low	45.91	25.51	25.54	26.08	26.50	33.32
30-Jun	Close	47.93	25.85	25.80	26.31	27.00	35.62
	Volume	5,894,000	191,800	156,200	98,200	240,400	349,400
July	High	51.02	26.07	26.45	27.00	27.34	36.91
	Low	47.53	25.23	25.50	26.15	26.56	35.18
31-Jul	Close	50.15	25.47	25.75	26.75	27.00	35.80
	Volume	7,762,900	93,900	117,300	99,400	129,600	198,600
August	High	52.00	25.52	26.43	27.00	27.29	37.40
	Low	48.85	24.79	25.58	25.81	26.55	34.80
29-Aug	Close	51.05	25.52	25.90	26.55	27.25	36.80
	Volume	6,064,200	50,100	72,100	107,300	116,700	199,200
September	High	51.80	26.00	26.40	26.94	27.60	37.75
	Low	47.50	25.10	25.80	25.92	26.75	35.50
30-Sep	Close	51.05	25.52	25.90	26.55	27.25	35.63
	Volume	6,555,600	40,900	82,300	86,800	95,600	156,600
October	High	52.12	26.40	26.35	27.09	27.95	39.72
	Low	47.90	25.30	25.95	25.90	27.25	35.61
31-Oct	Close	51.79	26.16	26.10	26.49	27.31	39.26
	Volume	7,308,100	44,000	95,200	113,900	71,500	198,700
November	High	54.00	26.42	26.90	26.65	28.39	41.40
	Low	51.40	25.70	25.60	25.76	27.25	38.54
28-Nov	Close	52.00	25.80	26.05	26.09	27.70	41.09
	Volume	6,412,600	34,500	95,800	91,000	94,200	146,200
December	High	54.14	26.40	26.05	26.53	28.00	41.66
	Low	51.50	25.68	25.30	25.75	26.86	38.03
31-Dec	Close	53.70	26.11	25.45	26.00	27.55	41.39
	Volume	4,330,300	119,200	95,600	83,500	99,200	180,200

As of the date of this Annual Information Form, the common shares of the Issuer 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 the Issuer's common shares. The Preference Shares, Series A of the Issuer are traded on the Toronto Stock Exchange under the symbol ENB.PR.A and the preferred securities of the Issuer, series 7.6%, 8.0% and 7.8%, are traded on the Toronto Stock Exchange under the symbols ENB.PR.B, ENB.PR.C and ENB.PR.D, respectively.

ITEM 9

DIRECTORS AND OFFICERS

DIRECTORS

The following table sets forth the names of the Directors of Enbridge Inc. effective December 31, 2003, 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 Issuer. The Issuer does not have an Executive Committee. As required, the Issuer 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[3,6] Naples, Florida	Corporate Director; Vice Chairman of the Board of Directors of El Paso Corporation (integrated energy company) in 2001; prior thereto, Chairman, President and/or Chief Executive Officer of the Coastal Corporation since 1993.	2002
JAMES J. BLANCHARD[4,5] Beverly Hills, Michigan	Senior Partner, Piper Rudnick (law firm), since 1996; prior thereto, United States Ambassador to Canada.	1999
J. LORNE BRAITHWAITE[4,5] Thornhill, Ontario	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	President & Chief Executive Officer of Enbridge since January 2001; prior thereto, President & Chief Operating Officer of Enbridge since September 2000; prior thereto, President & Chief Operating Officer – Energy Delivery of Enbridge since 1999.	2000
E. SUSAN EVANS[3,6] Calgary, Alberta	Corporate Director.	1996
WILLIAM R. FATT[3,6,7] Toronto, Ontario	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
RICHARD L. GEORGE[4,6] Calgary, Alberta	President and Chief Executive Officer of Suncor Energy Inc. (integrated oil and gas company).	1996
LOUIS D. HYNDMAN[3,4] Edmonton, Alberta	Senior Partner, Field Law LLP (law firm).	1993

Name[1] and Municipality of Residence	Principal Occupation for the Five Preceding Years	Year First Became a Director[2]
GEORGE K. PETTY[4,5] San Luis Obispo, California	Corporate Director; President & Chief Executive Officer of Telus Corporation (telecommunications company) from 1994 to 1999.	2001
ROBERT W. MARTIN[3,6,8] Toronto, Ontario	Corporate Director; Chairman of Silcorp Limited (convenience stores) from 1993 to 1999.	1992
DONALD J. TAYLOR[5,6] Jacksons Point, Ontario	Corporate Director; Chair of the Board of Directors of Enbridge Inc. since 1996.	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 Environment, Health & Safety 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. Mr. Fatt was a director of Unitel Inc., a company that instituted a compromise with its creditors on December 8, 1995. Mr. Fatt resigned as a director of Unitel in January 1996.

8. Mr. Martin was a director of the following corporations when they became bankrupt, made a proposal under the bankruptcy or insolvency legislation or were subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver manager or trustee appointed to hold their assets: Silcorp Ltd., Peoples Jewellers Limited and Confederation Life Insurance Company.

OFFICERS

The following table sets forth the names of the executive officers, their current office with the Issuer effective December 31, 2003, 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	President & Chief Executive Officer since January 2001; prior thereto, President & Chief Operating Officer from September to December 2000; prior thereto, President & Chief Operating Officer – Energy Delivery since 1999.
MEL F. BELICH Group Vice President, International & Corporate Law Calgary, Alberta	Group Vice President, International & Corporate Law since April 2003; prior thereto, Group Vice President, International since September 2000; prior thereto, Senior Vice President, International Development & Corporate Law, and Corporate Secretary since 1999.
J. RICHARD BIRD Group Vice President, Transportation North Calgary, Alberta	Group Vice President, Transportation North since May 2001; prior thereto, Group Vice President, Transportation since September 2000; prior thereto, Senior Vice President, Corporate Planning & Development since 1997.

Name, Position and Municipality of Residence	Position and Principal Occupations for the Five Preceding Years
BONNIE D. DUPONT Group Vice President, Corporate Resources Calgary, Alberta	Group Vice President, Corporate Resources since September 2000; prior thereto, Senior Vice President, Human Resources & Public Affairs since 1999.
STEPHEN J.J. LETWIN Group Vice President, Distribution Services Calgary, Alberta	Group Vice President, Gas Strategy & Corporate Development since April 2003; prior thereto, Group Vice President, Distribution & Services since September 2000; prior thereto, President & Chief Operating Officer – Energy Services since 1999.
DAN C. TUTCHER Group Vice President, Transportation South Houston, Texas	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	Group Vice President & Chief Financial Officer since April 2003; prior thereto, Group Vice President, Planning & Development since September 2000; prior thereto, President, Enbridge Pipelines Inc.
JAMES A. SCHULTZ Senior Vice President Gormley, Ontario	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; prior thereto, Vice President Operations, EGDI, since January 1999; prior thereto, Senior Vice President, Planning & Business Services, EGDI, in 1998.
SCOTT R. WILSON Senior Vice President & Controller Calgary, Alberta	Senior Vice President & Controller since June 2003; prior thereto, Senior Vice President, Finance since April 2003; prior thereto, Vice President, Finance since October 2001; prior thereto, Vice President & Treasurer since 1998.
LEIGH S. CRUESS Vice President, Financial Services Calgary, Alberta	Vice President, Financial Services since April 2003; prior thereto, Vice President, Corporate Development since January 2000; prior thereto, Vice President of UtiliCorp United Inc. since 1996.
AL MONACO Senior Vice President, Planning & Development Calgary, Alberta	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.
DARBY J. WADE Vice President & General Counsel Calgary, Alberta	Vice President & General Counsel since September 2000; prior thereto, Director of Law & Commercial Affairs of Enbridge International Inc.
JOHN K. WHELEN Vice President & Treasurer Calgary, Alberta	Vice President & Treasurer since February 2002; prior thereto, Assistant Treasurer.

Name, Position and Municipality of Residence	Position and Principal Occupations for the Five Preceding Years
BLAINE G. MELNYK Corporate Secretary & Associate General Counsel Calgary, Alberta	Corporate Secretary & Associate General Counsel since September 2000; prior thereto, Senior Legal Counsel & Assistant Corporate Secretary.

The directors and officers of the Issuer beneficially owned, directly or indirectly, less than 1% of the Issuer's common shares. 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.

The following individuals were also Officers during the year ended December 31, 2003.

Name, Position and Municipality of Residence	Position and Principal Occupations for the Five Preceding Years
DEREK P. TRUSWELL Group Vice President & Chief Financial Officer Calgary, Alberta	Group Vice President & Chief Financial Officer from September 2000 to April 2003; prior thereto, Senior Vice President & Chief Financial Officer.
KARYN A. BROOKS Vice President & Controller Calgary, Alberta	Vice President & Controller from April 2000 to June 2003; prior thereto, Vice President, Financial Services, Transmission of TransCanada PipeLines Limited since August 1999; prior thereto, Vice President & Controller of TransCanada PipeLines Limited.

ITEM 10

LEGAL PROCEEDINGS

The information, which is found under note 21 “Commitments and Contingencies” of the Corporation’s audited consolidated financial statements, as at, and for the year ended, December 31, 2003, is incorporated by reference herein.

ITEM 11

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 B, C and D is Computershare Trust Company of Canada at its principal office in Calgary, Alberta.

ITEM 12

ADDITIONAL INFORMATION

The Issuer shall provide any person or company, upon request, to the Office of the Corporate Secretary of the Issuer at 3000, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8:

(a) when the securities of the Issuer are in the course of a distribution under a preliminary short form prospectus or a short form prospectus,

  (i) one copy of the latest Annual Information Form of the Issuer together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

  (ii) one copy of the comparative financial statements of the Issuer for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Issuer that have been filed, if any, for any period after the end of its most recently completed financial year;

  (iii) one copy of the information circular of the Issuer in respect of its most recent annual meeting of shareholders that involved the election of directors; and

  (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under subparagraphs (i), (ii), or (iii) above; or

(b) at any other time, one copy of any documents referred to in subparagraphs (a)(i), (ii) and (iii) above, provided that the Issuer may require the payment of a reasonable charge if the request is made by a person or company who is not a security holder of the Issuer.

Additional information, including Directors' and Officers' remuneration and indebtedness, principal holders of the Issuer's securities and options to purchase the Issuer's securities, and the interest of insiders in material transactions, all as at December 31, 2003, is contained in the Issuer's Management Information Circular dated March 4, 2004 furnished in connection with the Annual and Special Meeting of Shareholders to be held on May 5, 2004 for the purpose of, among other things, the election of directors. Additional financial information is provided in the Issuer's comparative financial statements for the year ended December 31, 2003. 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, 2003.

Management's Report

To the Shareholders of Enbridge Inc.

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

Management has established systems of internal control that provide reasonable assurance that assets are safeguarded from loss or unauthorized use and produce reliable accounting records for the preparation of financial information. The internal control system includes an internal audit function and an established code of business conduct.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are not officers or employees of the Company, has a specific responsibility for ensuring that management fulfills its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

PricewaterhouseCoopers LLP, appointed by the shareholders as the Company's independent auditors, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.



Patrick D. Daniel
President & Chief Executive Officer
January 23, 2004



Stephen J. Wuori
Group Vice President & Chief Financial Officer

Auditors' Report

To the Shareholders of Enbridge Inc.

We have audited the consolidated statements of financial position of Enbridge Inc. as at December 31, 2003 and 2002 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
January 23, 2004

Chartered Accountants

Comments by Auditors for U.S. Readers on Canada-U.S. Reporting Difference

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Corporation's financial statements, such as the changes in stock-based compensation and accounting for goodwill described in Note 1 to the consolidated financial statements. Our report to the shareholders dated January 23, 2004 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
January 23, 2004

Chartered Accountants

Consolidated Statements Of Earnings

(millions of Canadian dollars, except per share amounts) Year ended December 31,	2003	2002	2001
Revenues			
Gas sales	**3,061.7**	2,987.7	2,675.3
Transportation	**1,560.6**	1,296.6	1,177.6
Energy services	**233.0**	263.2	228.0
	4,855.3	4,547.5	4,080.9
Expenses			
Gas costs	**2,720.1**	2,578.0	2,202.8
Operating and administrative	**800.8**	834.1	739.1
Depreciation	**443.0**	403.9	392.5
Writedown of Enbridge Midcoast Energy assets *(Note 3)*	**–**	122.7	–
	3,963.9	3,938.7	3,334.4
Operating Income	**891.4**	608.8	746.5
Investment and Other Income *(Note 18)*	**208.2**	283.1	194.9
Gain on Sale of Assets to Enbridge Income Fund *(Note 3)*	**239.9**	–	–
Interest Expense *(Note 10)*	**(451.3)**	(422.0)	(437.1)
	888.2	469.9	504.3
Income Taxes *(Note 16)*	**(187.4)**	(102.1)	(66.7)
Earnings From Continuing Operations	**700.8**	367.8	437.6
Earnings From Discontinued Operations *(Note 5)*	**–**	242.3	45.3
Earnings	**700.8**	610.1	482.9
Preferred Security Distributions *(Note 12)*	**(26.7)**	(26.7)	(17.5)
Preferred Share Dividends *(Note 13)*	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**667.2**	576.5	458.5
Earnings Applicable to Common Shareholders			
Continuing Operations	**667.2**	334.2	413.2
Discontinued Operations	**–**	242.3	45.3
	667.2	576.5	458.5
Earnings Per Common Share *(Note 13)*			
Continuing Operations	**4.03**	2.09	2.63
Discontinued Operations	**–**	1.51	0.28
	4.03	3.60	2.91
Diluted Earnings Per Common Share *(Note 13)*			
Continuing Operations	**4.00**	2.06	2.60
Discontinued Operations	**–**	1.50	0.28
	4.00	3.56	2.88

Consolidated Statements Of Retained Earnings

(millions of Canadian dollars, except per share amounts) Year ended December 31,	2003	2002	2001
Retained Earnings at Beginning of Year	**1,128.1**	812.3	581.3
Earnings Applicable to Common Shareholders	**667.2**	576.5	458.5
Effect of Change in Accounting for Stock-Based Compensation	**–**	(5.4)	–
Preferred Securities Issue Costs	**–**	(4.2)	–
Common Share Dividends	**(283.9)**	(251.1)	(227.5)
Retained Earnings at End of Year	**1,511.4**	1,128.1	812.3
Dividends Paid Per Common Share	**1.66**	1.52	1.40

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

Consolidated Statements Of Cash Flows

(millions of Canadian dollars) Year ended December 31,	2003	2002	2001
Cash Provided By Operating Activities			
Earnings from continuing operations	**700.8**	367.8	437.6
Charges/(credits) not affecting cash			
Depreciation	**443.0**	403.9	392.5
Equity less than/(in excess of) cash distributions	**(22.1)**	(44.6)	1.2
Gain on sale of assets to Enbridge Income Fund	**(239.9)**	–	–
Gain on reduction of ownership interest	**(50.0)**	(10.0)	(23.4)
Gain on sale of securities	**–**	(21.4)	–
Writedown of EGD regulatory receivable	**26.0**	–	–
Writedown of Enbridge Midcoast Energy assets	**–**	122.7	–
Future income taxes	**85.8**	(64.7)	3.4
Other	**21.4**	(21.0)	(75.6)
Changes in operating assets and liabilities *(Note 19)*	**(569.8)**	151.6	(323.1)
Cash provided by operating activities of discontinued operations	**–**	26.3	1.9
	395.2	910.6	414.5
Investing Activities			
Acquisitions *(Note 4)*	**(78.3)**	(289.3)	(599.1)
Long-term investments	**(50.5)**	(1,282.7)	(41.8)
Additions to property, plant and equipment	**(391.3)**	(729.9)	(683.3)
Proceeds on redemption of Enbridge Commercial Trust preferred units *(Note 8)*	**24.9**	–	–
Sale of assets to Enbridge Income Fund *(Note 3)*	**331.2**	–	–
Sale of Energy Services business *(Note 5)*	**–**	993.3	–
Sale of Enbridge Midcoast Energy assets *(Note 3)*	**–**	529.3	–
Sale of securities and other assets	**–**	184.3	–
Repayments by/(loans to) affiliate	**427.2**	358.1	(280.6)
Changes in construction payable	**(3.7)**	(14.8)	(14.0)
Other	**–**	–	(2.9)
	259.5	(251.7)	(1,621.7)
Financing Activities			
Net change in short-term borrowings and short-term debt	**359.8**	(1,180.9)	1,521.4
Long-term debt issues	**150.0**	247.4	905.6
Long-term debt repayments	**(725.0)**	(382.7)	(979.6)
Non-recourse long-term debt issued by joint ventures	**538.3**	–	–
Non-recourse long-term debt repaid by joint ventures	**(663.8)**	–	–
Non-controlling interests	**(4.0)**	0.2	(4.1)
Preferred securities issued	**–**	193.5	–
Common shares issued	**70.9**	293.1	23.3
Enbridge Energy Management shares issued *(Note 8)*	**–**	421.9	–
Preferred security distributions	**(26.7)**	(26.7)	(17.5)
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common shares dividends	**(283.9)**	(251.1)	(227.5)
	(591.3)	(692.2)	1,214.7
Increase/(Decrease) in Cash	**63.4**	(33.3)	7.5
Cash at Beginning of Year	**40.7**	74.0	66.5
Cash at End of Year	**104.1**	40.7	74.0

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

Consolidated Statements Of Financial Position

(millions of Canadian dollars) December 31,	2003	2002
Assets		
Current Assets		
Cash	**104.1**	40.7
Accounts receivable and other	**1,138.8**	817.5
Gas in storage	**809.8**	583.8
	2,052.7	1,442.0
Property, Plant and Equipment, net *(Note 6)*	**8,530.9**	6,947.6
Long-Term Investments *(Note 8)*	**2,390.9**	3,371.5
Receivable from Affiliate	**169.8**	701.5
Deferred Amounts and Other Assets *(Note 9)*	**486.5**	315.8
Future Income Taxes *(Note 16)*	**192.5**	209.0
	13,823.3	12,987.4
Liabilities And Shareholders' Equity		
Current Liabilities		
Short-term borrowings	**649.6**	247.5
Accounts payable and other	**894.1**	714.1
Interest payable	**97.0**	102.6
Current maturities and short-term debt *(Note 10)*	**674.9**	652.3
Current portion of non-recourse long-term debt *(Note 11)*	**34.2**	–
	2,349.8	1,716.5
Long-Term Debt *(Note 10)*	**5,243.1**	6,040.3
Non-Recourse Long-Term Debt *(Note 11)*	**752.4**	–
Future Income Taxes *(Note 16)*	**829.0**	837.4
Non-Controlling Interests *(Note 8)*	**523.0**	560.8
	9,697.3	9,155.0
Shareholders' Equity		
Share capital		
Preferred securities *(Note 12)*	**532.4**	533.7
Preferred shares *(Note 13)*	**125.0**	125.0
Common shares *(Note 13)*	**2,239.9**	2,169.0
Retained earnings	**1,511.4**	1,128.1
Foreign currency translation adjustment	**(147.0)**	12.3
Reciprocal shareholding *(Note 8)*	**(135.7)**	(135.7)
	4,126.0	3,832.4
Commitments and Contingencies *(Note 21)*		
	13,823.3	12,987.4

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

Approved by the Board:



Donald J. Taylor
Chair



Robert W. Martin
Director

Notes to the Consolidated Financial Statements

Enbridge Inc. (Enbridge or the Company) is a leader in the transportation and distribution of energy. 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 common carrier and feeder pipelines that transport crude oil and other liquid hydrocarbons.

Gas Pipelines

Gas Pipelines includes proportionately consolidated investments in transmission pipelines that transport natural gas.

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. From May 2001 to October 2002, the Company, through its subsidiary, Enbridge Pipelines Inc., owned 100% of Enbridge Midcoast Energy Inc., which is now a wholly owned subsidiary of EEP. Enbridge Income Fund is a publicly traded income fund whose primary operations include a 50% interest in a gas transmission 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, as well as gas service operations, including the Company's proportionately consolidated investment in Aux Sable and natural gas gathering and processing operations through an equity investment in AltaGas Services Inc.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 22. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with generally accepted accounting principles 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. Other investments are accounted for at cost.

The Company's gas distribution activities within the Gas Distribution and Services segment are conducted primarily through a wholly-owned subsidiary, Enbridge Gas Distribution Inc. (Enbridge Gas). The fiscal year-end of Enbridge Gas is September 30 and its results are consolidated on a one quarter lag basis, which reflects the results of Enbridge Gas operations in accordance with its regulatory, tax and operating cycles. Accordingly, references to "December 31" mean the financial position of Enbridge Gas as at September 30 and references to the "year ended December 31" mean the results of Enbridge Gas for the year ended September 30. Events subsequent to September 30 may provide additional information relating to items included in the financial statements of Enbridge Gas and may reveal conditions existing at the financial statement date that affect the estimates involved in the preparation of the financial statements. All such information that becomes available prior to completion of the Enbridge Inc. consolidated financial statements would be used in evaluating the estimates made and the financial statements would be adjusted where necessary.

Regulation

The Company's Liquids Pipelines, Gas Pipelines, and gas distribution activities within the Gas Distribution and Services segment are subject to regulation by various authorities, including the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers. 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.

Revenue Recognition

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 the Gas Distribution and Services segment 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 design as mandated by the regulatory authority. Certain other operations recognize revenue under the terms of enforceable, committed long-term delivery contracts.

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 there is reasonable expectation 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 functional currency of the Company's foreign operations, except for certain financing and investing operations, is the U.S. dollar. The Company also holds a Euro dollar equity investment in a foreign operation in Spain. These operations, which include those of proportionately consolidated U.S. dollar investments and the Euro dollar equity investment, are self-sustaining and 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 assumed. 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

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

Gas in Storage

Natural gas in storage is recorded in inventory at 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 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 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

Depreciation of property, plant and equipment generally is provided on a straight-line basis over the estimated service lives of the assets.

Future Removal and Site Restoration Costs

Future removal and site restoration costs are not determinable due to the indeterminable life of certain assets. Accordingly, no provision has been made for these costs. There is also reasonable expectation that any costs incurred will be recovered through future tolls when they become payable.

Depreciation expense for Gas Distribution and Services operations includes a provision for future removal and site restoration costs at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation.

Deferred Amounts

The Company defers certain charges which the regulatory authorities permit to be recovered through future rates. These charges are recognized when regulatory approval for these recoveries has been received. Other deferred charges are amortized straight-line 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 hedge agreements.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. Effective January 1, 2002, the Company adopted the standard of the Canadian Institute of Chartered Accountants (CICA) related to goodwill and other intangible assets. Under the standard, goodwill is not amortized but is tested for impairment at least annually and written down to fair value if the criteria for impairment are met. The standard has been applied prospectively.

Goodwill arising from the acquisition of Midcoast Energy Resources, Inc. in May 2001 (sold to EEP in October 2002) was amortized on a straight-line basis over 30 years prior to the adoption of the new standard. Results of operations for the year ended December 31, 2001 included goodwill amortization of $7.2 million. This amortization reduced both earnings per common share and diluted earnings per common share by $0.05 for the year ended December 31, 2001.

Derivative Financial Instruments

Gains and losses on financial instruments used to hedge the Company's net investment in foreign operations are included in the foreign currency translation adjustment in shareholders' equity. Amounts received or paid related to derivative financial instruments used to hedge the currency risk of cash flows from foreign currency denominated transactions are recognized concurrently with the hedged cash flows. Amounts received or paid related to derivative financial instruments used to hedge the price of energy commodities are recognized as part of the cost of the underlying physical purchases. For other derivative financial instruments used for hedging purposes, amounts received or paid, including any gains and losses realized upon settlement, are recognized over the term of the hedged item.

The Company applies settlement accounting to 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.

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 the Gas Distribution and Service segment 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.

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

Stock-Based Compensation

Effective January 1, 2002, the Company adopted the CICA standard for stock-based compensation. The standard required retroactive application for certain stock compensation awards as a charge to opening retained earnings without restatement of prior periods. Upon adoption, a charge to opening retained earnings of $5.4 million was recorded relating to outstanding stock appreciation rights, which expire in 2004.

Effective January 1, 2003, the Company early adopted new requirements in the CICA standard for stock-based compensation. The standard now requires the Company to apply the fair value based method of accounting for all awards granted. This method has been applied on a prospective basis and has resulted in a charge to income, in the year of adoption, of $1.9 million.

Comparative Amounts

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

New Accounting Standards

Impairment of Long-lived Assets

A new standard is in effect, for fiscal years beginning on or after April 1, 2003, for recognizing, measuring and disclosing impairment of long-lived assets held for use. The standard requires that an impairment loss be recognized in an amount equal to the difference between carrying value and fair value when the carrying value of a long-lived asset exceeds the expected undiscounted future cash flows. A recoverability test will be performed on asset groups as events or circumstances change in order to determine whether or not the assets are impaired. The Company is currently assessing the impact of the standard, if any, on its financial statements, and will adopt the standard for the fiscal year commencing January 1, 2004.

Hedging Relationships

A new guideline is in effect, for fiscal years beginning on or after July 1, 2003, for identifying, designating and documenting hedge relationships, and assessing their effectiveness. The guideline provides parameters on the conditions necessary for hedge accounting to be applied, but does not specify the methods to be used in its application. The guideline, however, does require that the Company adopt an accounting policy for assessing the effectiveness of its hedge relationships. Any ineffectiveness is to be recognized in income for the period. The Company is currently assessing the impact of the guideline, if any, on its financial statements, and will adopt the guideline for the fiscal year commencing January 1, 2004.

Generally Accepted Accounting Principles

A new standard is in effect, for all fiscal years beginning on or after October 1, 2003, for identifying appropriate sources of generally accepted accounting principles, and the doctrines that constitute generally accepted accounting principles. Any changes to accounting policies resulting from the adoption of this standard are to be applied prospectively. At present, the standard has an exemption for rate-regulated operations. The Company is currently assessing the impact of this standard and its related exemption, if any, on the financial statements.

Asset Retirement Obligations

A new standard is in effect, for fiscal years beginning on or after January 1, 2004, for recognizing, measuring and disclosing liabilities for asset retirement obligations and the associated asset retirement costs. A similar standard has been adopted by the Financial Accounting Standards Board in the United States, effective for fiscal years beginning after June 15, 2002. This new standard is not expected to have a material impact on the Company’s financial statements.

Consolidation of Variable Interest Entities

A new guideline is in effect, for all annual and interim periods beginning on or after November 1, 2004, for applying consolidation principles to entities subject to control on a basis other than through ownership of voting interests. A similar standard has been adopted by the Financial Accounting Standards Board in the United States (FIN 46), effective for interim periods commencing after July 15, 2003. If the interpretation of the Canadian standard is consistent with FIN 46, it would result in the consolidation of Enbridge Income Fund as described in Note 22.

2. SEGMENTED INFORMATION

Year ended December 31, 2003

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution & Services	International	Corporate[1]	Consolidated
Revenues	**821.5**	**222.1**	**–**	**3,785.4**	**26.2**	**0.1**	**4,855.3**
Gas costs	**–**	**–**	**–**	**(2,720.1)**	**–**	**–**	**(2,720.1)**
Operating and administrative	**(288.8)**	**(41.2)**	**–**	**(415.9)**	**(30.5)**	**(24.4)**	**(800.8)**
Depreciation	**(142.6)**	**(56.7)**	**–**	**(237.6)**	**(2.0)**	**(4.1)**	**(443.0)**
Operating income/(loss)	**390.1**	**124.2**	**–**	**411.8**	**(6.3)**	**(28.4)**	**891.4**
Investment and other income/(expense)	**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 equity charges	**(102.1)**	**(58.7)**	**–**	**(162.2)**	**(0.5)**	**(161.4)**	**(484.9)**
Income taxes	**(77.9)**	**(32.0)**	**(118.7)**	**(115.8)**	**1.0**	**156.0**	**(187.4)**
Earnings/(loss) applicable to common shareholders	**213.5**	**70.1**	**234.3**	**153.6**	**72.3**	**(76.6)**	**667.2**

Year ended December 31, 2002

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution & Services	International	Corporate[1]	Consolidated
Revenues	787.7	–	1,219.0	2,513.5	27.2	0.1	4,547.5
Gas costs	–	–	(1,051.4)	(1,526.6)	–	–	(2,578.0)
Operating and administrative	(282.5)	–	(109.5)	(410.4)	(19.0)	(12.7)	(834.1)
Depreciation	(150.6)	–	(17.3)	(229.5)	(2.9)	(3.6)	(403.9)
Writedown of Enbridge Midcoast Energy Assets	–	–	(122.7)	–	–	–	(122.7)
Operating income/(loss)	354.6	–	(81.9)	347.0	5.3	(16.2)	608.8
Investment and other income	4.8	66.3	44.8	32.1	64.0	71.1	283.1
Interest and preferred equity charges	(99.8)	–	(28.1)	(161.7)	(1.6)	(164.4)	(455.6)
Income taxes	(70.0)	(18.5)	14.1	(93.1)	0.3	65.1	(102.1)
Earnings/(loss) applicable to common shareholders	189.6	47.8	(51.1)	124.3	68.0	(44.4)	334.2
Earnings from discontinued operations							242.3
Earnings applicable to common shareholders							576.5

Year ended December 31, 2001

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	722.9	–	681.5	2,645.7	30.8	–	4,080.9
Gas costs	–	–	(558.9)	(1,643.9)	–	–	(2,202.8)
Operating and administrative	(258.7)	–	(53.3)	(392.0)	(19.0)	(16.1)	(739.1)
Depreciation	(139.8)	–	(24.1)	(223.3)	(2.5)	(2.8)	(392.5)
Operating income/(loss)	324.4	–	45.2	386.5	9.3	(18.9)	746.5
Investment and other income	13.7	57.8	43.1	5.5	27.0	47.8	194.9
Interest and preferred equity charges	(106.0)	(0.1)	(26.2)	(162.4)	(0.1)	(166.7)	(461.5)
Income taxes	(67.7)	(16.2)	(24.9)	(40.0)	(0.6)	82.7	(66.7)
Earnings/(loss) applicable to common shareholders	164.4	41.5	37.2	189.6	35.6	(55.1)	413.2
Earnings from discontinued operations							45.3
Earnings applicable to common shareholders							458.5

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

3 Segmented information of all years is restated consistent with the change in segments in the fourth quarter of 2003.

Total Assets

(millions of dollars) December 31,	2003	2002
Liquids Pipelines	**3,406.0**	3,468.5
Gas Pipelines	**1,649.7**	1,243.8
Sponsored Investments	**1,396.3**	850.8
Gas Distribution and Services	**6,156.4**	5,543.0
International	**835.7**	830.7
Corporate	**379.2**	1,050.6
	13,823.3	12,987.4

Additions to Property, Plant and Equipment

(millions of dollars) Year ended December 31,	2003	2002	2001
Liquids Pipelines	**123.4**	255.7	216.8
Gas Pipelines	**11.3**	–	–
Sponsored Investments	**–**	128.9	85.2
Gas Distribution and Services	**249.0**	315.0	314.1
International and Corporate	**7.6**	7.4	23.7
	391.3	707.0	639.8
Discontinued Operations	**–**	22.9	43.5
	391.3	729.9	683.3

2. SEGMENTED INFORMATION *(continued)*

Geographic Information

Revenues[1]

(millions of dollars) Year ended December 31,	2003	2002	2001
Canada	**3,739.4**	3,102.3	3,317.7
United States	**1,089.6**	1,418.0	736.8
Other	**26.3**	27.2	26.4
	4,855.3	4,547.5	4,080.9

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,	2003	2002
Canada	**6,747.3**	6,733.6
United States	**1,776.6**	204.8
Other	**7.0**	9.2
	8,530.9	6,947.6

3. DISPOSITIONS

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. Enbridge's net investment in Alliance Canada was $333.6 million at December 31, 2002 and was classified as a long-term investment. The net assets of Enbridge Pipelines (Saskatchewan) Inc. consist primarily of property, plant and equipment and comprised $86.5 million of Enbridge Inc.'s total property, plant and equipment balance at December 31, 2002.

Enbridge Midcoast Energy

In October 2002, the Company closed the sale of the United States assets of Enbridge Midcoast Energy to EEP, including the Northeast Texas assets described in Note 4. The book value of the assets was written down by $82.2 million, after tax, to reflect fair value based on the proceeds of $1,289.3 million. The Company received cash proceeds of approximately $529.3 million with the remaining consideration in the form of assumed affiliate debt.

4. ACQUISITIONS

Cushing to Chicago Pipeline System

In September 2003, the Company acquired 90% of the outstanding shares of CCPS Transportation L.L.C., owner of the Cushing to Chicago Pipeline System. Of the total purchase price, $78.3 million was paid on the date of acquisition. Payment of the remaining US$65.0 million depends upon completion of reversal of the flow of the pipeline and must be paid no later than December 31, 2004 to allow reversal to proceed. The acquisition was accounted for using the purchase method and the results of operations have been included in the consolidated statement of earnings from the date of acquisition. The amount paid was allocated to property, plant and equipment.

Northeast Texas

In March 2002, the Company acquired natural gas gathering and processing facilities in Northeast Texas for cash consideration of $289.3 million. These assets are included in the sale described in Note 3. The results of operations have been included in the consolidated statement of earnings for the period of ownership.

(millions of dollars)	
Fair Value of Assets Acquired	
Property, plant and equipment	242.3
Goodwill	56.2
Working capital deficiency	(9.2)
	289.3
Purchase Price	
Cash	288.2
Transaction costs	1.1
	289.3

Midcoast Energy Resources, Inc.

On May 11, 2001, the Company acquired all the outstanding shares of Midcoast Energy Resources, Inc., a Houston-based energy company, for cash consideration of $561.8 million and the assumption of long-term debt. This business is included in the sale described in Note 3. The acquisition was accounted for using the purchase method and the results of operations have been included in the consolidated statements of earnings from the date of acquisition until they were sold in October 2002.

(millions of dollars)	
Fair Value of Assets Acquired	
Property, plant and equipment	677.3
Working capital deficiency	(37.2)
Goodwill	328.9
Future income taxes	(39.0)
Other non-current assets	37.8
	967.8
Purchase Price	
Cash	554.5
Long-term debt assumed	406.0
Transaction costs	7.3
	967.8

Frontier Pipeline Company

The Company acquired an additional 34.0% interest in Frontier Pipeline Company for $46.0 million in December 2001, increasing the Company's ownership to 77.8%. The purchase price was allocated primarily to property, plant and equipment.

5. DISCONTINUED OPERATIONS

The sale of the Company's operations that provide energy products and services to retail and commercial customers, including the water heater rental program, closed in May 2002.

Selected financial information related to discontinued operations is as follows.

Earnings

(millions of dollars) Year ended December 31,	2002	2001
Gain on disposition, net of tax	240.0	–
Earnings	2.3	45.3
Earnings from discontinued operations	242.3	45.3

Selected Earnings Information

(millions of dollars) Year ended December 31,	2002	2001
Revenues	181.9	463.0
Income tax expense	34.6	2.5
Allocated interest expense	12.1	35.4

6. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) December 31, 2003	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	**2.4%**	**2,453.5**	**1,038.0**	**1,415.5**
Pumping Equipment, Buildings, Tanks and Other	**3.9%**	**2,215.0**	**690.7**	**1,524.3**
Land and Right-of-Way	**1.9%**	**34.1**	**16.0**	**18.1**
Under Construction	**—**	**47.0**	**—**	**47.0**
		4,749.6	**1,744.7**	**3,004.9**
Gas Pipelines				
Pipeline	**3.7%**	**1,544.4**	**196.6**	**1,347.8**
Land and Right-of-Way	**2.9%**	**36.6**	**4.5**	**32.1**
Metering and Other	**2.9%**	**85.6**	**11.6**	**74.0**
Under Construction	**—**	**6.4**	**—**	**6.4**
		1,673.0	**212.7**	**1,460.3**
Gas Distribution and Services				
Gas Mains	**4.3%**	**1,866.4**	**320.2**	**1,546.2**
Gas Services	**4.5%**	**1,811.1**	**370.1**	**1,441.0**
Regulating and Metering Equipment	**3.7%**	**581.9**	**106.2**	**475.7**
Storage	**2.7%**	**283.1**	**40.7**	**242.4**
Computer Technology	**8.0%**	**124.1**	**74.5**	**49.6**
Other	**5.4%**	**325.6**	**58.4**	**267.2**
		4,992.2	**970.1**	**4,022.1**
Other	**6.6%**	**66.7**	**23.1**	**43.6**
		11,481.5	**2,950.6**	**8,530.9**

(millions of dollars) December 31, 2002	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.5%	2,489.7	1,030.0	1,459.7
Pumping Equipment, Buildings, Tanks and Other	4.2%	2,166.1	711.6	1,454.5
Land and Right-of-Way	1.7%	34.3	16.0	18.3
Under Construction	—	92.7	—	92.7
		4,782.8	1,757.6	3,025.2
Gas Distribution and Services				
Gas Mains	3.0%	1,758.1	236.1	1,522.0
Gas Services	4.3%	1,682.3	287.3	1,395.0
Regulating and Metering Equipment	3.6%	551.5	81.4	470.1
Storage	2.7%	268.8	30.3	238.5
Computer Technology	25.0%	150.5	141.2	9.3
Other	4.0%	293.5	48.5	245.0
		4,704.7	824.8	3,879.9
Other	6.6%	61.1	18.6	42.5
		9,548.6	2,601.0	6,947.6

7. JOINT VENTURE

Alliance Pipeline Canada, Alliance Pipeline U.S., Aux Sable, and Alliance Canada Marketing, have been jointly controlled since April 1, 2003. Vector Pipeline Canada, and Vector Pipeline U.S. have been jointly controlled since October 1, 2003. The Company's proportionate share of earnings, cash flows and financial position related to these entities is summarized below, with the exception of Alliance Pipeline Canada for the period subsequent to June 30, 2003 as the Company's 50% interest in Alliance Pipeline Canada was sold effective June 30, 2003 to EIF.

(millions of dollars)	April 1, 2003 to December 31, 2003
Earnings	
Revenues	**421.7**
Gas sales	**(168.1)**
Operating and administrative	**(81.5)**
Depreciation	**(59.7)**
Interest expense	**(59.7)**
Investment and other income	**5.1**
Income taxes	**0.3**
Proportionate share of net earnings	**58.1**
Cash Flows	
Cash provided by operations	**99.4**
Cash provided by investing activities	**(1.4)**
Cash used in financing activities	**(197.7)**
Proportionate share of decrease in cash	**(99.7)**

7. JOINT VENTURE *(continued)*

(millions of dollars)	December 31, 2003
Financial Position	
Current assets	**118.7**
Property, plant and equipment, net	**1,562.2**
Other long-term assets	**102.9**
Current liabilities	**(122.6)**
Long-term debt	**(752.4)**
Other long-term liabilities	**(17.8)**
Proportionate share of net assets	**891.0**

Included in the Company's proportionate share of cash from joint ventures is $18.7 million held in trust, pursuant to finance agreements of the joint venture. Under these finance agreements, funds received from shippers, in settlement of transportation rates, as well as interest earned on trust account balances, are segregated in trust accounts and first applied to meet debt service and operating requirements. Amounts in excess of these requirements are transferred to a non-trust account for partnership distributions on a quarterly basis.

8. LONG-TERM INVESTMENTS

(millions of dollars) December 31,	Ownership Interest	2003	2002
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	22.8%	**25.0**	32.4
Gas Pipelines			
Alliance Pipeline Canada	—	**—**	333.6
Alliance Pipeline U.S.	—	**—**	345.0
Vector Pipeline	—	**—**	474.8
		—	1,153.4
Sponsored Investments			
The Partnership	12.2%	**743.6**	815.5
Enbridge Income Fund	41.9%	**—**	—
		743.6	815.5
Gas Distribution and Services			
AltaGas Services	40.3%	**210.7**	204.2
Noverco	32.1%	**36.7**	28.9
Aux Sable	—	**—**	135.0
Other		**16.0**	14.0
		263.4	382.1
International			
Compañía Logistica de Hidrocarburos *(CLH)*	25.0%	**531.2**	541.2
Corporate		**17.8**	17.2
Cost Investments			
Sponsored Investments			
Enbridge Income Fund		**380.2**	—
Gas Distribution and Services			
Noverco		**181.4**	181.4
FuelCell Energy/Global Thermoelectric		**25.0**	25.0
		206.4	206.4
International			
OCENSA Pipeline		**223.3**	223.3
		2,390.9	3,371.5

Equity investments include $536.4 million (2002 – $551.9 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 has been allocated to property, plant and equipment on the basis of estimated fair values and is amortized over the economic life of the assets.

Alliance Pipeline, Aux Sable and Vector Pipeline

In 2003, the Company invested $223.2 million (2002 – $315.3 million) in Alliance and Aux Sable, increasing the Company's interest from 37.1% to 50.0% in Alliance Pipeline Canada, 37.1% to 50% in Alliance Pipeline U.S. and 30.9% to 42.7% in Aux Sable. The purchase price was $36.9 million (2002 – ($7.1) million) less than the underlying net book value of the assets. This amount has been allocated to property, plant and equipment and is being amortized over the economic life of the assets.

On October 1, 2003 the Company invested $97.7 million in Vector, including the assumption of $61.5 million in debt, increasing the Company's ownership interest from 45% to 60%. The purchase price was $36.3 million less than the underlying net book value of the assets. This amount has been allocated to property plant and equipment and is being amortized over the economic life of the assets.

As a result of these additional investments, the Company established joint control (see Note 7). Therefore, the Company's interest in Alliance Pipeline Canada, Alliance Pipeline U.S., Aux Sable and Alliance Canada Marketing are accounted for as joint ventures effective April 1, 2003 and the Company's interest in Vector Pipeline Canada and Vector Pipeline U.S. are accounted for as joint ventures effective October 1, 2003. On June 30, 2003, the Company sold its 50% interest in Alliance Pipeline Canada to Enbridge Income Fund.

The Partnership

In October 2002, EEM, a partially-owned subsidiary, completed an initial public offering of 9,000,000 limited liability shares. The proceeds from the offering were used to purchase I-units, a new class of limited partnership interest from EEP. The Company purchased 17.2% of the EEM shares, increasing its total net investment in the Partnership to 14.1% from 12.9%. Although 82.8% of EEM is widely held, the Company has voting control of EEM. The Company's statement of financial position includes 100% of EEM's investment in EEP which totals $478.8 million (2002 – $529.9 million). The Company's net investment in the Partnership, after deducting the non-controlling interest of $396.4 million (2002 – $438.8 million), is $347.7 million (2002 – $376.7 million).

In 2003, EEP completed two public issuances of partnership units. As the Company elected not to participate in either of these offerings, its effective interest in EEP was reduced to 12.2% from 14.1%. This resulted in recognition of a total dilution gain of $20.3 million (2002 – $6.1 million), net of tax and minority interest.

Noverco

Noverco holds an approximate 10% reciprocal shareholding in the Company. As a result, the Company has a pro-rata interest of 3.2% (2002 – 3.2%) in its own shares. Both the equity investment in Noverco Inc. and shareholders' equity have been reduced by the reciprocal shareholding of $135.7 million (2002 – $135.7 million).

The Company owns a cost investment in Noverco of $181.4 million (2002 – $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%.

CLH

In 2002, the Company invested $430.8 million in CLH, a refined products transportation and storage company in Spain. The Company's 25% interest is accounted for by the equity method. Contingent consideration of up to 84.3 million Euros ($137.2 million) will become payable over the next three years if certain minimum annual and cumulative volume targets are met. The purchase price included $340.9 million representing the excess of purchase price over the underlying net book value of the assets. The excess has been allocated to property, plant and equipment and is being amortized over the economic life of the assets.

8. LONG-TERM INVESTMENTS *(continued)*

Enbridge Income Fund

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, EIF acquired the Company's 50% interest in the Canadian segment of the Alliance Pipeline together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. The Company has 14,500,000 subordinated trust units of EIF and 38,023,750 preferred units of Enbridge Commercial Trust (ECT), a direct subsidiary of EIF, at December 31, 2003. The subordinated trust units result in a 41.9% common equity interest in EIF.

The Company's $145.0 million initial investment in subordinated units of EIF was offset by a $145.0 million unrecognized gain resulting in a book value of nil. The unrecognized gain is being amortized into income over the life of the underlying assets of EIF and is included as a component of equity earnings.

The Company's 38 million preferred units are accounted for as a $380.2 million cost investment at December 31, 2003. 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 comparable to those of ordinary common units. As such, the approximate fair value of these preferred units, valued at the December 31, 2003 closing price of $12.89 per ordinary common unit, is $490.1 million.

OCENSA Pipeline

The Company owns a cost investment in the OCENSA Pipeline of $223.3 million (2002 – $223.3 million) which earns a fixed rate of return. The fair value of this investment is approximately $270.0 million, estimated using year-end market information and various assumptions. As no market exists for an instrument of this nature, the actual fair value in an open market may vary significantly.

Income from Equity Investments

(millions of dollars) **Year ended December 31,**	**2003**	**2002**	**2001**
Liquids Pipelines	**1.1**	1.0	8.5
Gas Pipelines	**31.6**	67.1	57.6
Sponsored Investments	**73.3**	40.9	23.3
Gas Distribution and Services	**19.9**	7.7	(9.7)
International	**45.7**	34.2	0.3
Corporate	**1.2**	—	—
	172.8	150.9	80.0

Consolidated retained earnings at December 31, 2003 includes undistributed earnings from equity investments of $130.5 million (2002 – $148.7 million).

9. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars) **Year ended December 31,**	**2003**	**2002**
Regulatory and contractual deferrals	**232.9**	159.6
Long-term portion of receivables from hedge counterparty	**127.7**	36.9
Deferred pension funding	**66.3**	72.7
Deferred financing charges	**37.3**	34.6
Other	**22.3**	12.0
	486.5	315.8

At December 31, 2003, $105.1 million (2002 – $102.9 million) was subject to amortization. Amortization expense of deferred amounts in 2003 was $18.4 million (2002 – $21.7 million; 2001 – $23.5 million). Accumulated amortization at the end of 2003 was $38.9 million (2002 – $27.2 million).

10. DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	2003	2002
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	300.0
Medium-term notes	6.66%	2005-2029	**622.7**	622.5
Other[1]			**58.7**	58.8
Gas Distribution and Services				
Debentures	11.00%	2004-2024	**635.0**	635.0
Medium-term notes	6.34%	2004-2032	**1,030.0**	1,105.0
Other			**9.5**	9.0
Corporate				
Senior term notes[2] *(US$275.0 million)*	8.08%	2005-2007	**397.8**	397.8
Medium-term notes	6.14%	2004-2032	**1,790.0**	1,788.7
Variable rate credit facility			**—**	400.0
Variable rate credit facility[3]			**—**	252.7
Preferred securities *(Note 12)*	7.79%	2048-2051	**17.6**	16.3
Other[4]			**1,156.7**	1,106.8
Total Debt			**5,918.0**	6,692.6
Current maturities of long-term debt			**450.0**	225.0
Other short-term debt			**224.9**	427.3
Current Maturities and Short-Term Debt			**674.9**	652.3
Long-Term Debt			**5,243.1**	6,040.3

1 Primarily commercial paper borrowings.

2 The principal amount is recorded at the swapped rate.

3 2002 included US$160.0 million.

4 Primarily commercial paper borrowings. Includes US$306.0 million (2002 – US$582.5 million).

Short-term debt in the amount of $1,000.0 million (2002 – $1,000.0 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, 2004 through 2008 are $450.0 million, $528.6 million, $440.0 million, $369.3 million and $220.0 million, respectively.

Interest Rate Management

(millions of dollars) December 31,	Weighted Average Effective Rate	2003 Notional Amounts	2002 Notional Amounts
Liquids Pipelines			
Commercial paper	6.04%	**25.4**	25.4
Corporate			
Senior term notes[1]	7.40%	**US$275.0**	US$275.0
Variable rate debt	2.30%	**—**	400.0

1 Subject to a cross-currency swap.

10 . DEBT *(continued)*

The weighted average effective rate reflects the interest rate of debt instruments after giving effect to interest swap agreements.

Interest Expense

(millions of dollars) December 31,	2003	2002	2001
Long-term debt	**431.7**	392.9	345.0
Commercial paper and other short-term debt	**20.2**	29.0	85.8
Short-term borrowings	**9.6**	9.6	12.2
Capitalized	**(10.2)**	(9.5)	(5.9)
	451.3	422.0	437.1

In 2003, total interest paid was $467.1 million (2002 – $429.3 million; 2001 – $452.2 million).

Credit Facilities

(millions of dollars) December 31, 2003	Committed	Uncommitted	Drawdowns
Liquids Pipelines	150.0	—	—
Gas Distribution and Services	659.0	6.5	14.5
Corporate	1,887.7	—	—
	2,696.7	6.5	14.5

Committed facilities carry a weighted average standby fee of 0.10% per annum on the unutilized portion. The committed facilities for Liquids Pipelines expire in 2004 and are extendible annually thereafter subject to the approval of lenders. The committed facilities for Gas Distribution and Services expire in 2004 and 2006 and are extendible annually thereafter subject to the approval of the lenders. The committed facilities for Corporate expire in 2004 and 2008 and are extendible annually thereafter subject to the approval of the lenders. Drawdowns under all of these facilities bear interest at prevailing market rates.

11 . NON-RECOURSE DEBT OF JOINT VENTURES

(millions of dollars) December 31,	2003
Credit Facilities (US$21.7 million)	**28.0**
Senior Notes:	
7.770% due 2015 (US$140.0 million)	**180.9**
6.996% due 2019 (US$153.4 million)	**198.3**
7.877% due 2025 (US$100.0 million)	**129.2**
4.591% due 2025 (US$146.2 million)	**189.0**
Obligations under capital leases (US$47.4 million)	**61.2**
	786.6
Less current portion of long-term debt (US$26.5 million)	**(34.2)**
	752.4

The debt of joint ventures is non-recourse to Enbridge. Security provided by the joint ventures is limited to all of the rights and assets of the individual joint venture and does not extend to the rights and assets of Enbridge, except to the extent of Enbridge's investment.

The Senior Notes may be redeemed by Alliance Pipeline U.S. at any time, at a price equal to the outstanding principal plus accrued but unpaid interest and a make-whole premium. Alliance Pipeline U.S. may be required to redeem the Senior Notes, in whole or in part, from proceeds received under insurance 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. Principal repayments commenced June 30, 2001 on the 6.996% Senior Notes, December 31, 2001 on the 7.770% Senior Notes, June 30, 2003 on the 4.591% Senior Notes and commences June 30, 2019 on the 7.877% Senior Notes. Principal repayments are due semi-annually thereafter in each instance and are closely tied to the recovery rates for capital depreciation and deferred income taxes contained in the transportation agreements.

Long-term debt maturities on joint venture borrowings for the years ending December 31, 2004 through 2008 are $34.2 million, $32.0 million, $56.0 million, $37.6 million and $38.0 million, respectively.

12. PREFERRED SECURITIES

The Company has $175.0 million of 7.6%, $200 million of 7.8%, and $175.0 million of 8.0% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after the fifth anniversary of each issue and have no stated maturity date. 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. As a result, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $532.4 million at December 31, 2003 (2002 – $533.7 million).

13. 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,	**2003**		**2002**		**2001**	
	Number of Shares	**Amount**	**Number of Shares**	**Amount**	**Number of Shares**	**Amount**
Balance at beginning of year	**169.7**	**2,169.0**	162.9	1,875.9	161.8	1,852.6
Dividend Reinvestment and Share Purchase Plan	**0.4**	**17.1**	0.2	8.3	0.2	7.2
Stock based compensation expense	**—**	**1.9**	—	—	—	—
Issued to Noverco	**—**	**—**	0.5	23.1	—	—
Public issue	**—**	**—**	5.0	225.4	—	—
Exercise of stock options and other	**1.8**	**51.9**	1.1	36.3	0.9	16.1
Balance at end of year	**171.9**	**2,239.9**	169.7	2,169.0	162.9	1,875.9

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, 2003, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $26.00 per share if redeemed on or prior to December 1, 2004; $25.75 if redeemed on or prior to December 1, 2005; $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.

13. SHARE CAPITAL *(continued)*

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 5.3 million shares (2002 – 5.3 million shares), resulting from the investment in Noverco.

The treasury stock method, used for calculating diluted earnings per share, uses an adjusted weighted average number of common shares outstanding, which reflects the effect of exercising all dilutive securities.

(number of common shares in millions) December 31,	2003	2002	2001
Weighted average shares outstanding	**165.5**	160.3	157.3
Effect of dilutive securities	**1.4**	1.7	1.5
Diluted weighted average shares outstanding	**166.9**	162.0	158.8

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 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 or announcement 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.

14. STOCK OPTION PLAN

The Company's Incentive Stock Option Plan (2002) includes fixed stock options and performance-based stock options. A maximum of 15 million common shares is reserved for issuance under the plan.

Fixed Stock Options

Full-time, key employees are granted options to purchase common shares that are exercisable at the market price of 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 February 6, 2013.

Outstanding Fixed Stock Options

(options in thousands; exercise price in dollars) December 31,	2003		2002		2001	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**5,042**	**32.16**	5,120	29.06	4,112	26.76
Options granted	**1,042**	**41.65**	1,024	43.80	2,024	30.11
Options exercised	**(1,244)**	**26.64**	(1,003)	26.31	(843)	19.27
Options cancelled or expired	**(99)**	**39.87**	(99)	37.59	(173)	34.47
Options at end of year	**4,741**	**35.96**	5,042	32.16	5,120	29.06
Options vested	**2,319**		2,639		2,853	

Fixed Stock Option Characteristics

(options in thousands; exercise price in dollars)
December 31, 2003

Options Outstanding				Options Vested	
Exercise Price Range	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
10.30-19.99	117	1.72	14.70	117	14.70
20.00-29.99	1,078	5.44	26.02	796	25.77
30.00-39.99	1,564	5.76	35.95	1,165	35.22
40.00-47.71	1,982	8.29	42.64	241	43.63
	4,741			2,319	

Performance-based Options

The Plan provides for the grant of performance-based stock options to executive officers that become exercisable based on the performance of the Company's common share price. Of the outstanding performance-based stock options as at December 31, 2003, 810,000 remain unexercisable and were granted September 16, 2002 at $46.30 per share. These performance-based stock options vest in equal annual installments over their five-year term and become exercisable, as to 50% of the grant, if the price on an Enbridge common share exceeds $61.00 for 20 consecutive trading days during the period September 16, 2002 to September 16, 2007 and, as to 100% of the grant, if the price of an Enbridge common share exceeds $71.00 for 20 consecutive trading days during the same aforementioned period. The term will extend to eight years if any of these options become exercisable before the end of the five-year term.

Outstanding Performance-based Options

(options in thousands; exercise price in dollars)
December 31,

	2003		2002		2001	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**2,045**	**37.73**	1,479	32.03	1,480	31.60
Options granted	**—**	**—**	810	46.30	65	41.13
Options exercised	**(549)**	**31.39**	(244)	31.66	—	—
Options cancelled	**—**	**—**	—	—	(66)	31.35
Options at end of year	**1,496**	**40.05**	2,045	37.73	1,479	32.03
Options vested	**686**	**32.67**	1,235	32.10	740	31.31

At December 31, 2003, the exercise prices of outstanding performance-based options ranged from $31.35 to $46.30 (2002 – $31.35 to $46.30; 2001 – $31.35 to $41.13). Outstanding performance-based options will expire over a period ending no later than September 16, 2010.

14. STOCK OPTION PLAN *(continued)*

Pro forma Compensation Expense

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

(millions of dollars) Year ended December 31,	**2003**	**2002**
Earnings applicable to common shareholders from continuing operations		
As reported	**667.2**	334.2
Total stock-based compensation expense [1]	**(5.9)**	(2.9)
Included as an expense in the statement of earnings [2]	**1.9**	—
Pro forma	**663.2**	331.3
Earnings applicable to common shareholders		
As reported	**667.2**	576.5
Total stock-based compensation expense [1]	**(5.9)**	(2.9)
Included as an expense in the statement of earnings [2]	**1.9**	—
Pro forma	**663.2**	573.6
Earnings per common share from continuing operations		
As reported	**4.03**	2.09
Pro forma	**4.01**	2.07
Earnings per common share		
As reported	**4.03**	3.60
Pro forma	**4.01**	3.58

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

2 Stock-based compensation recognized as an expense in the statement of earnings for options granted in 2003 as a result of the adoption of the fair valued based method January 1, 2003.

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

Year ended December 31,	**2003**	**2002**	**2003**	**2002**
	Fixed Stock Options		**Performance-based Options**	
Fair value per option	**$8.46**	$11.42	**—**	$ 7.65
Valuation assumptions				
Expected option term *(years)*	**8**	10	**—**	8
Expected volatility	**22%**	25%	**—**	24%
Expected dividend yield	**3.95%**	3.51%	**—**	3.46%
Risk-free interest rate	**5.24%**	5.33%	**—**	4.20%

15. 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, primarily natural gas. In order to manage these exposures for both shareholders and ratepayers, the Company utilizes derivative financial instruments to create offsetting positions to specific exposures. These instruments are not used for speculative purposes.

Derivative financial instruments involve credit and market 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 with approved forms of collateral. 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.

Foreign Exchange

The Company has an exposure to foreign currency exchange rates, primarily because of 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. In addition, cross currency swaps have been entered into to hedge the Company's exposure on its U.S. dollar denominated senior term notes.

Interest Costs

The Company enters into forward interest rate agreements, swaps and collars to swap floating rate debt to fixed and hedge against the effect of future interest rate movements on its variable rate debt. The Company monitors its debt portfolio mix of fixed and variable rate instruments and has entered into fixed to floating interest rate swaps, with notional amounts of $300.0 million, to manage the balance of fixed and floating rate debt.

Energy Commodity Costs

The Company uses over-the-counter natural gas price swaps, futures, options and collars to manage physical exposures that arise in the management of merchant capacity commitments to the Alliance and Vector pipelines. The Company also uses these derivative instruments to manage any exposures that may arise from physical asset optimization and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable Liquid Products L.P., 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 NGLs are fixed with swaps, or capped or collared with options.

Natural Gas Supply Management

The Company hedges a portion of the cost of future natural gas supply requirements of Enbridge Gas, as allowed by the regulator. Amounts paid or received under the hedge agreements are recognized as part of the cost of the natural gas purchases and are recovered through the ratemaking process. At December 31, 2003, the Company had entered into natural gas price swaps and options to manage the price for approximately 8.9%, or 13.1 billion cubic feet, of its forecast fiscal 2004 system gas supply.

15. FINANCIAL INSTRUMENTS *(continued)*

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.

December 31, (millions of dollars unless otherwise noted)	**2003**			**2002**		
	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	**535.8**	**(30.6)**	**2005-2022**	535.8	24.9	2005-2022
Euro cross currency swaps	**434.7**	**(46.1)**	**2004-2019**	371.1	(54.4)	2003
Forwards *(cumulative exchange amounts)*	**1,889.5**	**67.9**	**2004-2022**	1,993.0	(244.6)	2003-2022
Energy commodities						
Natural gas *(bcf)*	**63.6**	**12.4**	**2004-2008**	35.3	(1.5)	2003-2004
Natural gas supply management *(bcf)*	**13.1**	**(3.4)**	**2004**	5.9	(0.2)	2003
Interest rates						
Interest rate swaps	**561.0**	**1.9**	**2005-2029**	934.1	0.6	2003-2029
Forward interest rate swaps	**532.0**	**(1.0)**	**2004-2005**	—	—	—

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset 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 $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

As the Company has not settled any hedging instruments in advance of the hedged transactions, there were no deferred gains or losses for any of the Company's hedges of anticipated transactions at December 31, 2003 and 2002. A credit risk on derivative financial instruments amounted to $94.8 million at December 31, 2003 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.

The carrying amounts of all financial instruments, except for debt, approximate fair value. The fair value of debt does not include the effects of hedging.

Total Debt

(millions of dollars) December 31,	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**881.4**	**990.6**	981.3	1,084.5
Gas Distribution and Services	**1,674.5**	**1,972.1**	1,749.0	1,989.2
Corporate	**3,362.1**	**3,540.1**	3,962.3	4,081.3
	5,918.0	**6,502.8**	6,692.6	7,155.0

Non-recourse debt of joint ventures has a carrying value of $786.6 million and a fair value of $845.7 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. 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 $35.1 million at December 31, 2003 (2002 – $31.1 million).

16. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars) Year ended December 31,	2003	2002	2001
Earnings before income taxes	**888.2**	746.8	552.1
Combined statutory income tax rate	**35.6%**	38.0%	41.0%
Income taxes at statutory rate	**316.2**	283.8	226.3
Increase/(decrease) resulting from:			
Tax rate changes on future income tax balances	**6.2**	8.1	(67.5)
Future income taxes related to regulated operations	**(34.5)**	(36.7)	(35.7)
Non-taxable items, net	**(70.5)**	(99.5)	(28.2)
Lower foreign tax rates	**(44.4)**	(42.2)	(36.8)
Large Corporations Tax	**18.1**	16.9	18.8
Other	**(3.7)**	6.3	(7.7)
Income Taxes	**187.4**	136.7	69.2
Continuing operations	**187.4**	102.1	66.7
Discontinued operations	**—**	34.6	2.5
	187.4	136.7	69.2
Effective income tax rate	**21.1%**	18.3%	12.5%

In 2003, income taxes paid amounted to $202.9 million (2002 – $105.2 million; 2001 – $110.5 million).

16. INCOME TAXES *(continued)*

Components of Future Income Taxes

(millions of dollars) December 31,	2003	2002
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	**368.0**	313.8
Differences in accounting and tax bases of investments	**368.2**	525.7
Other	**187.2**	110.1
	923.4	949.6
Future Income Tax Assets		
Loss carryforwards	**241.7**	283.0
Other	**45.2**	38.2
	286.9	321.2
Total Net Future Income Tax Liability	**636.5**	628.4

Accumulated future income taxes related to rate-regulated operations which have not been recorded in the accounts amounted to $551.2 million at December 31, 2003 (2002 – $511.2 million). Had the liability method been prescribed by the regulatory authorities for ratemaking purposes, such amounts would have been recorded and recovered in revenues.

At December 31, 2003, the Company has recognized the benefit of unused tax loss carryforwards of $708.8 million. Unused tax loss carryforwards expire as follows: 2004 – $0.1 million; 2005 – $3.4 million; 2006 – $26.1 million; 2007 – $71.9 million; 2008 – $56.8 million, 2009 – $17.4 million and 2010 and beyond – $533.1 million.

Geographic Components of Pretax Earnings and Income Taxes

(millions of dollars) Year ended December 31,	2003	2002	2001
Earnings before income taxes			
Canada	**693.0**	346.1	297.2
United States	**40.1**	(5.0)	103.8
Other	**155.1**	128.8	103.3
Continuing operations	**888.2**	469.9	504.3
Discontinued operations	**—**	276.9	47.8
	888.2	746.8	552.1
Current income taxes			
Canada	**108.4**	154.8	44.4
United States	**(10.9)**	3.2	8.9
Other	**4.1**	8.8	10.0
Continuing operations	**101.6**	166.8	63.3
Discontinued operations	**—**	36.9	20.1
	101.6	203.7	83.4
Future income taxes			
Canada	**116.6**	(54.5)	(9.0)
United States	**(31.0)**	(10.5)	12.4
Other	**0.2**	0.3	—
Continuing operations	**85.8**	(64.7)	3.4
Discontinued operations	**—**	(2.3)	(17.6)
	85.8	(67.0)	(14.2)
Current and future income taxes			
Continuing operations	**187.4**	102.1	66.7
Discontinued operations	**—**	34.6	2.5
	187.4	136.7	69.2

17. POST-EMPLOYMENT BENEFITS

Pension Plans

The Company has three 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 pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides either non-contributory defined benefit pension benefits or contributory defined contribution pension benefits to U.S. employees of Enbridge.

Defined Benefit Plans

Retirement benefits under defined benefit plans are based on employees' years of service and remuneration. Contributions made by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2003. The effective dates of the most recent actuarial valuations and the next required actuarial valuations are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	January 1, 2002	January 1, 2005
Enbridge U.S.	January 1, 2003	January 1, 2004
Gas Distribution and Services	January 1, 2002	January 1, 2005

Pension costs under the defined benefit pension plans reflect management's best estimates of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.

Defined Contribution Plans

Contributions are generally based on the employee's age and/or years of service. For the Enbridge U.S. pension plan, contributions to the defined contribution plans are also based on employee contributions. For defined contribution pension benefits, pension cost equals amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions

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

17. POST-EMPLOYMENT BENEFITS *(continued)*

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability using the accrual method.

(millions of dollars)	2003	2002	2003	2002
	OPEB		Pension Benefit	
Change in benefit obligation				
Benefit obligation, January 1	**160.5**	132.3	**710.1**	742.7
Service cost	**5.8**	4.2	**20.0**	18.7
Interest cost	**10.6**	8.8	**46.8**	45.9
Amendments	**(3.3)**	—	**—**	0.7
Employee contributions	**0.4**	0.3	**—**	0.1
Actuarial loss	**0.8**	31.4	**68.8**	8.5
Benefits paid	**(5.6)**	(5.7)	**(37.8)**	(37.9)
Divestitures	**—**	(10.6)	**—**	(67.8)
Effect of exchange rate changes	**(13.5)**	(0.2)	**(19.6)**	(0.8)
Benefit obligation, December 31	**155.7**	160.5	**788.3**	710.1
Fair value of plan assets				
Fair value of plan assets, January 1	**35.5**	29.6	**933.1**	1,076.7
Actual return on plan assets	**0.8**	3.0	**109.7**	(20.3)
Employer's contributions	**11.2**	8.5	**11.2**	19.7
Employee contributions	**0.4**	0.3	**—**	0.1
Benefits paid	**(5.6)**	(5.7)	**(37.8)**	(37.9)
Other	**—**	—	**(1.7)**	(2.3)
Divestitures	**—**	—	**—**	(100.9)
Effect of exchange rate changes	**(6.1)**	(0.2)	**(27.8)**	(2.0)
Fair value of plan assets, December 31	**36.2**	35.5	**986.7**	933.1
Asset/(Liability)				
Benefit obligation, December 31	**(155.7)**	(160.5)	**(788.3)**	(710.1)
Fair value of plan assets, December 31	**36.2**	35.5	**986.7**	933.1
Surplus/(deficit)	**(119.5)**	(125.0)	**198.4**	223.0
Contribution after measurement date	**—**	—	**2.9**	—
Unrecognized prior service cost	**0.5**	3.4	**19.0**	20.8
Unrecognized plan liability	**29.4**	36.2	**—**	—
Unrecognized net loss/(gain)	**28.0**	31.5	**21.0**	4.8
Recorded asset/(liability)	**(61.6)**	(53.9)	**241.3**	248.6

Major Categories of Plan Assets

(millions of dollars) Year ended December 31,	%	2003	2002	%	2003	2002
		OPEB			Pension Benefit	
Equity securities	**0.0%**	**—**	—	**58.5%**	**639.1**	542.2
Debt securities	**85.9%**	**31.1**	32.2	**37.1%**	**404.4**	447.8
Other	**14.1%**	**5.1**	3.3	**4.4%**	**47.8**	35.7
	100.0%	**36.2**	35.5	**100.0%**	**1,091.3**	1,025.7
Assets attributable to Non-Consolidated Affiliates		**—**	—		**(104.6)**	(92.6)
Total Assets		**36.2**	35.5		**986.7**	933.1

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

Rate of Return on Plan Assets

(millions of dollars) Year ended December 31,	%	2003	2002	%	2003	2002
		OPEB			Pension Benefit	
Canadian Plans						
Equity securities	**—**	**—**	—	**60.0%**	**8.75%**	9.25%
Fixed income securities	**100.0%**	**4.5%**	4.5%	**40.0%**	**5.00%**	6.00%
					7.25%	7.75%
United States Plan						
Equity securities	**—**	**—**	—	**60.0%**	**8.75%**	9.25%
Fixed income securities	**100.0%**	**4.50%**	4.50%	**40.0%**	**5.00%**	6.00%
					7.25%	8.00%

The Pension Funds exist to ensure that pension benefits will be paid. 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 above table reflects both the target allocation percentage for each of the categories presented at the end of the period, as well as, the expected long-term rate of return on assets, both on a weighted-average basis. 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) Year ended December 31,	2003	2002	2003	2002
	OPEB		Pension Benefit	
Minimum contributions required	**—**	—	**—**	—
Additional contributions	**11.2**	8.5	**11.2**	19.7
Total contributions	**11.2**	8.5	**11.2**	19.7
Contributions expected to be paid in 2004	**10.6**		**14.8**	

Net Pension Plan and OPEB Costs Incurred

(millions of dollars) Year ended December 31,	2003	2002	2001
Benefits earned during the year	**27.7**	25.2	26.3
Interest cost on projected benefit obligations	**57.4**	54.5	55.2
Actual return on plan assets	**(110.5)**	16.7	(125.1)
Actuarial gain in the year	**69.6**	38.0	45.0
Amount credited/(charged) to the EEP	**(10.2)**	(1.7)	5.5
Pension and OPEB costs incurred	**34.0**	132.7	6.9

Net Pension Plan and OPEB Costs Recognized

(millions of dollars) Year ended December 31,	2003	2002	2001
Benefits earned during the year	**27.7**	25.2	26.3
Interest cost on projected benefit obligations	**57.4**	54.5	55.2
Expected return on plan assets	**(64.8)**	(75.3)	(93.7)
Amortization and deferral of unrecognized amounts	**15.3**	6.9	(6.8)
Amount credited/(charged) to EEP	**(10.2)**	(1.7)	5.5
Pension and OPEB cost/(credit) recognized	**25.4**	9.6	(13.5)

The above tables reflect the funded status, recorded pension and OPEB assets and liabilities and 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 other plans, the Company's pension cost was $9.4 million (2002 – $3.6 million credit; 2001 – $4.0 million cost). The pension asset was $71.4 million (2002 – $73.1 million). The Company's OPEB cost totaled $7.0 million (2002 – $6.8 million; 2001 – $5.9 million). The OPEB liability was $10.0 million (2002 – $8.4 million). These net benefits or liabilities are recorded on the balance sheet in Deferred Amounts and Other Assets. The pension and OPEB assets and obligations for discontinued operations were included in the sale transaction.

Economic Assumptions

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

Year ended December 31,	2003	2002	2001	2003	2002	2001
		OPEB			Pension Benefit	
Discount rate	**6.79%**	6.95%	7.15%	**6.75%**	6.81%	7.06%
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%	**7.25%**	7.79%	7.79%

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

Year ended December 31,	2003	2002	2001	2003	2002	2001
		OPEB			Pension Benefit	
Discount rate	**6.31%**	6.79%	6.95%	**6.29%**	6.75%	6.81%
Average rate of salary increases				**4.00%**	4.00%	4.00%

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%	4.5%	2011
Other Medical	4.5%	4.5%	2004
Enbridge U.S.	14%	5.5%	2011

A 1% increase in the assumed medical and dental care trend rate would result in a change of $26.2 million in the accumulated post-employment benefit obligations and a change of $2.8 million in OPEB cost. A 1% decrease in the assumed medical and dental care trend rate would result in a change of $20.7 million in the accumulated post-employment benefit obligations and a change of $2.1 million in OPEB cost.

18. INVESTMENT AND OTHER INCOME

(millions of dollars) Year ended December 31,	2003	2002	2001
Equity investments	**146.3**	143.5	56.7
Gain on reduction of EEP ownership interest	**50.0**	10.0	23.4
EEM's equity income from EEP	**26.5**	7.4	23.3
Minority interest in EEM (equity income and dilution gain)	**(25.9)**	(4.0)	—
Cost investments	**67.2**	61.1	51.9
Investment income	**32.9**	22.9	16.3
Allowance for equity funds used during construction	**3.2**	5.3	3.9
Gain/(loss) on foreign currency contracts	**(87.2)**	0.1	(1.7)
Gain on sale of marketable securities	**—**	21.4	—
Other	**(4.8)**	15.4	21.1
	208.2	283.1	194.9

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of dollars) Year ended December 31,	2003	2002	2001
Accounts receivable and other	**(354.5)**	75.0	(583.7)
Gas in storage	**(224.8)**	76.0	(145.8)
Deferred amounts and other assets	**(78.9)**	72.4	(77.6)
Accounts payable and other	**93.9**	(76.4)	493.1
Interest payable	**(5.5)**	4.6	(9.1)
	(569.8)	151.6	(323.1)

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

20. RELATED PARTY TRANSACTIONS

Neither, EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. These services, which are charged at cost in accordance with service agreements, amount to $128.9 million (2002 — $97.2 million; 2001 — $56.2 million) for EEP and $4.7 million for EIF, which began operation on June 30, 2003.

Vector uses the services of Enbridge, a 60% interest owner, to operationally manage its business. These services, which are charged at cost in accordance with service agreements, amounted to $3.3 million for 2003 (2002 — $4.1 million; 2001 — $3.4 million).

EGD acquires its customer care services from CustomerWorks Limited Partnership under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services, which amounted to $95.5 million in 2003 (2002 — $71.8 million).

EGD has contracted for gas transportation services from Alliance Pipeline Limited Partnership and Vector Pipeline Limited Partnership. EGD is charged market prices for these services, which amounted to $40.7 million in 2003 (2002 — $41.3 million; 2001 — $34.8 million) for Alliance Pipeline, and $23.2 million in 2003 (2002 — $25.2 million; 2001 — $20.7 million) for Vector Pipeline.

A subsidiary of the Company earns rental revenue from CustomerWorks Limited Partnership for the use of an automated billing system. In 2003, this revenue amounted to $25.5 million (2002 — $35.1 million). CustomerWorks Limited Partnership began operations on January 1, 2002.

In 2003, Enbridge Gas Services Inc. purchased $33.6 million (2002 — $6.3 million; 2001 — nil) of gas from Enbridge Marketing (US) Inc.

The Company also provides consulting and other services to affiliates. 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 trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

Enbridge Gas Distribution Inc.

The remediation of discontinued manufactured gas plant sites may result in future costs to Enbridge Gas. In October 2002, a claim was filed for $55 million in damages relating to a certain manufactured gas plant site. Enbridge Gas filed a statement of defence in June 2003 denying liability. 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. Enbridge Gas expects that costs, if any, not recovered through insurance would be recovered through rates. As such, management does not believe that the outcome will have a material impact on the financial statements.

In October 2002, the Supreme Court of Canada granted an Application for Leave to Appeal to a customer who commenced an action against Enbridge Gas claiming that the OEB-approved late payment penalties charged to customers were contrary to Canadian federal law. The Court heard the plaintiff's appeal of the Ontario Court of Appeal's decision on October 9, 2003 and reserved issuing judgment.

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners have commenced an action, which they will be applying for certification as 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. Since the outcome is indeterminable, the Company has made no provision for any potential liability.

Enbridge Energy Partners

Enbridge Energy Company, Inc. (EEC), which holds a portion of the Company's equity interest in 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$248 million at December 31, 2003.

22. 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,**	**2003**	**2002**	**2001**
Earnings under Canadian GAAP	**700.8**	610.1	482.9
Preferred security distributions [1]	**(26.7)**	(26.7)	(17.5)
Stock-based compensation [2]	**—**	(12.1)	(15.2)
Loss on ineffective hedges [5]	**(53.8)**	—	—
Change in income due to consolidation of EIF [7]	**(2.3)**	—	—
Change in gain due to consolidation of EIF [7]	**(173.0)**	—	—
Tax effect of the above adjustments	**51.5**	4.9	6.1
Future income tax recovery/(expense) [3]	**—**	—	92.8
Earnings under U.S. GAAP	**496.5**	576.2	549.1
Unrealized net gain/(loss) on cash flow hedges [6]	**66.9**	19.5	(150.8)
Reclassification adjustment on cash flow hedges [6]	**80.6**	—	—
Foreign currency translation adjustment [6]	**(159.6)**	(1.3)	15.1
Comprehensive income	**484.4**	594.4	413.4
Earnings per common share	**3.00**	3.55	3.45
Diluted earnings per common share	**2.98**	3.51	3.41

22. UNITED STATES ACCOUNTING PRINCIPLES *(continued)*

Financial Position

(millions of dollars) December 31,	2003		2002	
	Canada	United States	Canada	United States
Cash [7]	**104.1**	**131.7**	40.7	42.7
Accounts receivable and other [6,7]	**1,138.8**	**1,192.8**	817.5	843.4
Property, plant and equipment [7]	**11,481.5**	**12,778.2**	9,548.6	9,506.6
Accumulated depreciation [7]	**2,950.6**	**2,974.2**	2,601.0	2,596.3
Long-term investments [7]	**2,390.9**	**2,010.7**	3,371.5	3,421.0
Deferred amounts [3,7]	**486.5**	**1,355.8**	315.8	1,178.7
Short-term borrowings	**649.6**	**649.6**	247.5	256.8
Accounts payable and other [7]	**894.1**	**1,000.7**	714.1	915.0
Current maturities and short-term debt [7]	**674.9**	**721.4**	652.3	658.5
Long-term debt [1]	**5,243.1**	**6,761.0**	6,040.3	6,612.5
Future income taxes [3,6]	**636.5**	**1,429.2**	628.4	1,403.0
Non-controlling interests [7]	**523.0**	**599.7**	560.8	560.8
Preferred securities [1]	**532.4**	**—**	533.7	—
Retained earnings	**1,511.4**	**1,289.5**	1,128.1	1,089.8
Additional paid in capital [2]	**—**	**27.3**	—	27.3
Foreign currency translation adjustment [6]	**(147.0)**	**—**	12.3	—
Accumulated other comprehensive loss [6]	**—**	**(116.6)**	—	(103.2)

1 Preferred Securities

Under U.S. GAAP, the full amount of the Company's Preferred Securities and related distributions would be recognized as debt and interest expense, respectively. The Preferred Securities have a fair market value of $625.5 million at December 31, 2003 (2002 — $565.0 million).

2 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. 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 for options will remain only for those options granted prior to adoption, January 1, 2002, of the Canadian accounting standard for stock-based compensation.

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 Canadian GAAP, the Company's performance-based options did not give rise to compensation expense. Under U.S. GAAP, the Company's performance-based options, which vested during 2002 and 2001, gave rise to pre-tax compensation expense of $12.1 million and $6.9 million respectively. No performance-based options vested in 2003. In addition, under U.S. GAAP in 2001, the Company's Stock Appreciation Rights (SARs) were accounted for using the intrinsic value method, which resulted in pre-tax compensation expense of $8.3 million, whereas, under Canadian GAAP, SARs did not give rise to compensation expense.

3 Future Income Taxes

Canadian GAAP requires that the effects of tax rate reductions be recognized when they are substantively enacted. Under U.S. GAAP, the effect of tax rate reductions cannot be recognized until enacted. In 2000, the Company recognized $92.8 million of earnings related to substantively enacted tax rate reductions that are recognized in 2001 under U.S. GAAP.

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. The additional deferred income taxes under U.S. GAAP include the difference between capital cost allowance and depreciation of property, plant and equipment of $551.2 million (2002 – $549.3 million) and the incremental revenue required for the recovery of unrecorded taxes of $286.6 million (2002 – $316.0 million).

4 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. See Note 7 for summarized financial information of joint ventures.

5 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 derivative's fair value 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 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 fair value of derivative instruments is offset through other comprehensive income, until the variability in cash flows being hedged is recognized in earnings in future accounting periods.

In order to qualify for hedge accounting, FAS 133 requires that extensive documentation be maintained and that hedge effectiveness tests prescribed by that standard be met at both the inception of a hedge relationship and on a periodic, ongoing basis. Management maintains the necessary level of documentation required to qualify for hedge accounting under FAS 133. However, in one instance during 2003, certain instruments were classified as ineffective hedges resulting in a loss after tax of $32.3 million under U.S. GAAP.

6 Accumulated Other Comprehensive Loss

At December 31, 2003, Accumulated Other Comprehensive Loss consists of an accumulated foreign currency translation adjustment of $(131.5) million (2002 – $28.1 million) and net unrealized gains of $14.9 million (2002 – $(131.3) million) both for derivative financial instruments due to cash flow hedges, including a reclassification adjustment in 2003. The reclassification adjustment of $80.6 million relates to the change in classification of hedging instruments between periods.

Of the Accumulated Other Comprehensive Loss of $116.6 million, the Company estimates that approximately $5.6 million, representing unrecognized net losses on derivative activities at December 31, 2003, is expected to be reclassified into earnings during the next twelve months.

7 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 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. FIN 46 defines a variable interest entity as an entity which has one or more of the following characteristics:

1) The equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including the equity holders.

2) The equity investors as a group lack one or more of the following essential characteristics of a controlling financial interest:

a. The direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights that have a significant effect on the success of the entity.

b. The obligation to absorb the expected losses of the entity.

c. The right to receive the expected residual returns of the entity. The equity investors do not have that right if their return is capped by the entity's governing documents or arrangements with other variable interest holders or the entity.

3) The equity investors have voting rights that are not proportionate to their economic interests, and the activities of the entity involve or are conducted on behalf of an investor with a disproportionately small voting interest.

The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities.

FIN 46 is immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003. For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 is required to be applied by the first fiscal year or interim period ending after December 15, 2003. The Company has not identified any material variable interest entities created, or interests in variable entities obtained, before January 31, 2003, which would require consolidation or disclosure under FIN 46.

On June 30, 2003, the Company formed Enbridge Income Fund (EIF), a publicly traded entity with assets purchased from the Company. The Company has a 41.9% equity interest in EIF, 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.

EIF is considered a variable interest entity as the equity investors lack the right to receive the expected residual returns of the entity. FIN 46 defines expected residual returns as the expected positive variability in the fair value of EIF's net assets exclusive of variable interests. The preferred units participate in the positive variability as they receive a coupon rate that floats with changes in the cash distributions made

to the equity holders of EIF. Consequently, the equity investors lack the right to receive the expected residual returns of the entity.

The Company is the primary beneficiary of EIF through a combination of the 41.9% equity interest and the preferred unit interest. Under U.S. GAAP, the results of EIF are consolidated with a 27.7% minority interest. The assets and liabilities of EIF have been measured at the same amounts as they were prior to the transfer to EIF and the gain is recorded based on the equity issued to external third parties.

The U.S. GAAP adjustment reflecting the consolidation of EIF includes a $380.2 million reduction to long-term investments, a $76.7 million increase in non-controlling interests, a reduction in the pre-tax gain on sale from $239.9 million to $66.9 million, and net income is reduced by $2.3 million.

The following accounts of EIF are consolidated for the purposes of the U.S. GAAP financial statements as at December 31, 2003.

Cash	*$*	*27.6*	*million*
Accounts receivable and other	*$*	*34.2*	*million*
Property, plant and equipment	*$*	*1,273.1*	*million*
Deferred amounts	*$*	*31.5*	*million*
Accounts payable and other	*$*	*31.0*	*million*
Current portion of long-term debt	*$*	*40.0*	*million*
Long-term debt	*$*	*1,022.6*	*million*
Future income taxes	*$*	*2.8*	*million*

The consolidation of EIF increases cash by $27.6 million and the statement of cash flows would reflect an increase in cash from operations of $30.4 million, cash from investing activities would decrease by $384.3 million, and cash used in financing activities would increase by $381.5 million.

Supplemental Disclosure — Pro Forma Compensation Expense

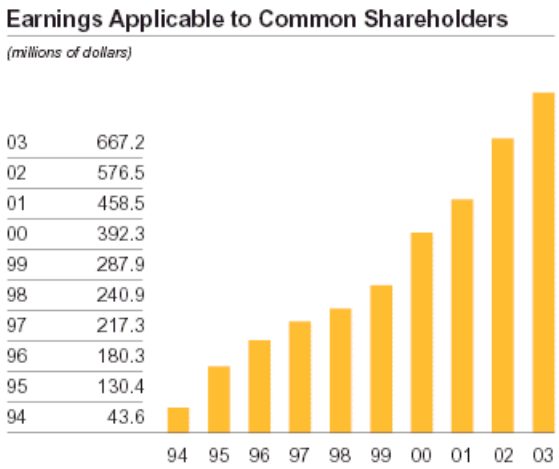
U.S. GAAP requires that, where the fair value based method is not used to measure compensation expense, pro forma earnings and earnings per share, calculated as if the fair value based method had been used, must be disclosed. In Canada, these requirements apply to options granted on or after January 1, 2002 and therefore, the Company's Canadian GAAP disclosure does not include any options granted prior to that date.

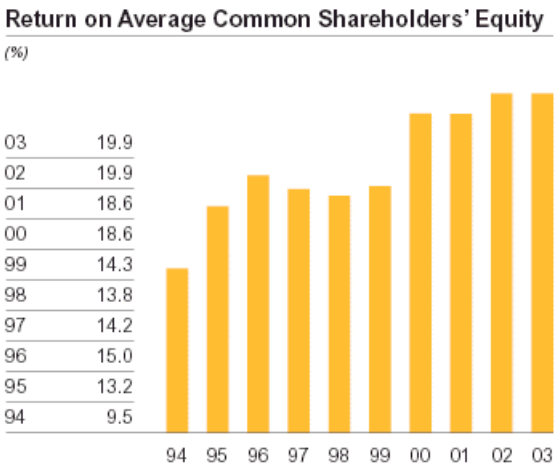
(millions of dollars except per share amounts) Year ended December 31,	2003	2002	2001
Earnings under U.S. GAAP			
As reported	**496.5**	576.2	549.1
Stock-based compensation expense	**(7.9)**	(7.3)	(4.6)
Included as an expense in the statement of earnings	**1.9**	—	—
Pro forma	**490.5**	568.9	544.5
Earnings per common share			
As reported	**3.00**	3.55	3.45
Stock-based compensation expense	**0.04**	0.05	0.03
Pro forma	**2.96**	3.50	3.42
Diluted earnings per common share			
As reported	**2.98**	3.51	3.41
Stock-based compensation expense	**0.04**	0.04	0.03
Pro forma	**2.94**	3.47	3.38

The fair value of stock options was calculated in the same manner, using the same assumptions, as disclosed in Note 14 except that for Canadian GAAP, only awards granted since the adoption of the CICA standard for stock-based compensation on January 1, 2002 are included. Assumptions used for U.S. GAAP comparatives in 2001 are as follows.

Year ended December 31,	2001
Risk-free interest rate	5.38%
Expected life *(years)*	10
Expected volatility	25%
Expected quarterly dividends	$0.38

The weighted average grant-date fair value of options granted during 2001 under the fixed option plan was $10.09.





In 2003, Enbridge increased earnings in each of its five operating segments.

CONSOLIDATED RESULTS

Financial Highlights [1]

(millions of Canadian dollars, except per share amounts)	2003	2002	2001
Earnings Applicable to Common Shareholders			
Liquids Pipelines	**213.5**	189.6	164.4
Gas Pipelines	**70.1**	47.8	41.5
Sponsored Investments	**234.3**	(51.1)	37.2
Gas Distribution and Services	**153.6**	124.3	189.6
International	**72.3**	68.0	35.6
Corporate	**(76.6)**	(44.4)	(55.1)
Earnings from continuing operations	**667.2**	334.2	413.2
Discontinued operations	**—**	242.3	45.3
	667.2	576.5	458.5
Earnings Per Share			
Earnings — Continuing operations	**4.03**	2.09	2.63
Earnings — Discontinued operations	**—**	1.51	0.28
	4.03	3.60	2.91
Diluted Earnings Per Share			
Earnings – Continuing operations	**4.00**	2.06	2.60
Earnings – Discontinued operations	**—**	1.50	0.28
	4.00	3.56	2.88
Total Assets	**13,823.3**	12,987.4	13,127.7
Total Long-term Liabilities	**7,347.5**	7,438.5	6,885.8
Dividends Per Common Share	**1.66**	1.52	1.40
Common Share Dividends	**283.9**	251.1	227.5

1 *Financial Highlights have been prepared in accordance with Canadian Generally Accepted Accounting Principles.*

Earnings for the year ended December 31, 2003 were $667.2 million, or $4.03 per share, compared with $576.5 million, or $3.60 per share, in 2002. Growth in earnings from all core business segments were noted, further buoyed by the positive effect of colder than normal weather in the Enbridge Gas Distribution franchise area in 2003. Significant incremental earnings were also noted in both Liquids and Gas Pipelines primarily due to the Company's increased ownership interest in both Alliance Pipeline and Vector Pipeline. 2003 also marked the completion of the Terrace Phase III project and the storage cavern project, both providing a positive contribution to net earnings.

Significant factors and variances affecting consolidated earnings are as follows:

- Sponsored Investments includes a $169.1 million after-tax gain on the sale of assets to Enbridge Income Fund (EIF) in 2003.
- Sponsored Investments included an $82.2 million after-tax writedown recorded in 2002, relating to the Enbridge Midcoast Energy (Midcoast) assets.
- Sponsored Investments includes a $20.3 million dilution gain in 2003 relating to two unit issuances by Enbridge Energy Partners (EEP). The prior year included only one dilution gain from EEP of $6.1 million.
- Gas Distribution and Services includes the positive effect of colder than normal weather of $46.1 million in 2003. In 2002, warm weather negatively affected earnings by $29.3 million. The positive weather effect in 2003 is partially offset by several regulatory disallowances in 2003, including a $4.6 million outsourcing disallowance, a $7.1 million gas cost disallowance, and a $26.0 million regulatory receivable writedown.
- The results of Noverco, included in Gas Distribution and Services, reflect a $6.0 million dilution gain relating to a unit issuance by Gaz Metro Limited Partnership.
- Corporate included a $17.8 million after-tax gain on a sale of marketable securities in 2002.
- Each year includes the effect of the Alberta 0.5% tax rate reductions. The 2003 results also include the effect of a higher federal future tax rate since federal surtax will apply when large corporations tax is eliminated. These tax rate changes result in a $7.1 million net charge to earnings in 2003 compared with a net recovery of $1.4 million in the prior year.
- Discontinued operations included a $240.0 million after-tax gain on the sale of the retail Energy Services business in 2002.

Enbridge made several strategic achievements during the year.

- The creation of the Enbridge Income Fund, on June 30, 2003, seeded with assets from the Company.
- Growth in core businesses through the acquisition of additional interests in the Alliance Pipeline, the Aux Sable NGL facility, and the Vector Pipeline. The Company also acquired a 90% interest in the Cushing-to-Chicago Pipeline System during 2003. Upon reversal, this pipeline will provide crude oil shippers with access to new markets.
- EEP has also actively pursued growth through a number of strategic acquisitions, which will support earnings growth in the future.
- The completion and placement into service of the Terrace Phase III expansion on April 1, 2003. This increased delivery capacity by 140,000 barrels per day on the Enbridge and Lakehead Systems.

For the year ended December 31, 2002, earnings from continuing operations were $334.2 million, or $2.09 per share, compared with $413.2 million, or $2.63 per share, in 2001. Growth in earnings from the Liquids Pipelines and International operations, as well as higher earnings from EEP, were more than offset by the loss on sale of the United States assets of Enbridge Midcoast Energy, warmer weather than 2001, and the positive impact on earnings of income tax rate reductions in 2001.

Dividends paid on common shares increased in each of the last four years from growth in the dividend per share and a higher number of outstanding common shares. The quarterly dividend per share increased to $0.415 in the first quarter of 2003 from $0.38 per share established in the first quarter of 2002. In the first quarter of 2001, the quarterly dividend was raised to $0.35. This represents annual increases of 9.2%, 8.6% and 8.5%, respectively, and reflects the sustained growth in earnings over the period.

In 2003, the Company changed its financial reporting segments to better reflect the business operations and management structure of the Company. All financial information has been restated to reflect the new segments.

CORPORATE STRATEGY

Enbridge's resources are focused on three broad strategic thrusts and three areas of increased emphasis. The major strategies are to:

- continue to expand the Company's core platforms, increase its asset base through a variety of means including organic growth and acquisition of strategic assets. The four core platforms are Liquids Pipelines, Gas Pipelines, Gas Distribution and Services and International;
- capitalize on the Enbridge Energy Partners and Enbridge Income Fund vehicles through acquisition of assets from third parties and transfers of mature assets from Enbridge; and,
- focus on operational excellence, including the application of incentive regulatory structures.

Strategic emphasis is placed on increasing the Company's North American footprint, increasing the scale of operations, and developing and applying new technologies. Enbridge's proposed actions with respect to these strategies are described in the "Outlook" for each business unit.

The achievement of the Company's major strategies is dependent on successful mitigation of business risks, discussed in each of the business segments. Enbridge believes it has identified and mitigated the risks, to the extent practical.

Enbridge remained on track with this strategy in 2003 and is committed to identifying and implementing the actions required to create value and sustainable growth.

LIQUIDS PIPELINES

Financial Results

(millions of Canadian dollars)	2003	2002	2001
Enbridge System	**162.0**	123.7	111.1
Athabasca System	**44.8**	41.2	29.9
NW System	**8.3**	9.5	9.5
Saskatchewan System	**3.1**	6.4	5.9
Feeder Pipelines and Other	**(4.7)**	8.8	8.0
	213.5	189.6	164.4

Business Activities

Liquids Pipelines activities consist of the operation of the Company's pipelines that transport crude oil, natural gas liquids and refined products.

The mainline pipeline, comprised of the Enbridge System and the Lakehead System (the portion of the mainline pipeline in the United States is operated by Enbridge and owned by EEP), is the world's longest crude oil pipeline system and 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 to Eastern Canada and serves all of the major refining centres in the Province of Ontario, as well as the Midwest region of the United States.

Enbridge also owns the Athabasca System and the NW System. The Athabasca System is a 545-kilometre (339-mile) pipeline that transports synthetic and heavy oil from north of Fort McMurray in Northern Alberta to the pipeline hub at Hardisty, Alberta. The Athabasca System also includes the MacKay River and Christina Lake lateral feeder lines and tankage facilities, as well as the Company's interest in the Hardisty Cavern Storage Partnership. The NW System is an 864-kilometre (540-mile) pipeline that transports crude oil from Norman Wells, in the Northwest Territories to Zama, Alberta.

During the third quarter of 2003, the Company acquired a 90% interest in the Cushing-to-Chicago Pipeline System. This is a 1,050-kilometre (650-mile) pipeline that transports crude oil from Cushing, Oklahoma to Chicago, Illinois, with a service capacity of 300,000 barrels per day, including 4.3 million barrels of tankage. The pipeline is currently inactive except for an approximately 145-kilometre (90-mile) portion of the pipeline from Cushing to Caney, Kansas. Subject to acceptance of proposed tolling arrangements by Canadian producers and regulatory approval, Enbridge intends to reverse the flow of this pipeline by the end of 2004. The reversed line would be renamed the Spearhead Pipeline and would provide pipeline service from the Chicago area to the Cushing market.

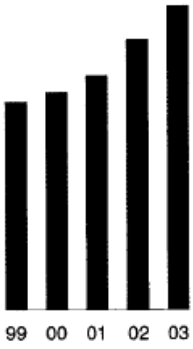
Feeder Pipelines and Other primarily includes a number of liquids pipelines in the United States (Frontier, Toledo, Mustang and Chicap), as well as business development costs related to Liquids Pipelines activities.

Results of Operations

Earnings from Liquids Pipelines were $213.5 million for the year ended December 31, 2003, an increase of $23.9 million from 2002. The results reflect higher earnings from the Enbridge and Athabasca Systems, which include incremental earnings from Terrace Phase III and the cavern storage partnership. Offsetting these positive factors is a provision for costs associated with toll complaints on the Frontier pipeline and higher business development costs as the Company evaluates growth opportunities. In addition, the Saskatchewan System was sold to Enbridge Income Fund effective June 30, 2003; however, the Company continues to have an interest in this pipeline through its 41.9% ownership of Enbridge Income Fund, included in the Sponsored Investments segment.

Liquids Pipelines Earnings

(millions of dollars)



99	146.0
00	152.5
01	164.4
02	189.6
03	213.5

Earnings were $189.6 million for the year ended December 31, 2002, compared with $164.4 million for 2001. The higher earnings resulted from expansions of the Enbridge and Athabasca Systems. Higher earnings from the Enbridge System were due to the request from shippers in mid-2001 to construct Phase III of the Terrace expansion, which resulted in incremental earnings and to Phase II of the Terrace expansion, which was placed into service in early 2002. These increases were partially offset by an adjustment to the power allowance credit due to shippers as a result of Terrace operating at less than capacity. The Athabasca System generated higher earnings due to the construction of new laterals and tankage, which commenced operations in the second half of 2002.

Enbridge System

In 2003, Enbridge System earnings were $38.3 million higher than last year primarily due to full year earnings from the Terrace Phase II expansion, incremental earnings from Terrace Phase III, which commenced operations ahead of schedule on April 1, 2003, lower depreciation rates as approved by the National Energy Board (NEB), as well as recognized power cost savings. Also contributing to the year-over-year variance is the negative effect of an adjustment to the power allowance credit due to shippers in 2002 as a result of Terrace operating at less than capacity.

Earnings from the Enbridge System increased to $123.7 million in 2002 from $111.1 million in 2001. The increase was mainly due to higher earnings from the Terrace expansion as Phase II was placed into service in early 2002 and Phase III was triggered in mid-2001. The increase in Terrace earnings was partially offset by an adjustment to the power allowance credit due to shippers as a result of Terrace operating at less than capacity.

Tolls on the Enbridge System are governed by the provisions of the Incentive Tolling Settlement (ITS). The ITS, which has been approved by the NEB, is in its second five-year term which expires on December 31, 2004. Under the ITS, tolls are determined based on a starting revenue requirement, which is adjusted each year for 75% of the change in the Gross Domestic Product Implicit Price Index. The ITS allows the Company and its customers to share in cost savings, protects Enbridge from fluctuations in volumes, and incorporates additional incentive mechanisms for electric power cost savings. Since electricity is used to power the pumping stations, power costs are a significant expense. The Company is allowed to earn a separate return on facilities expansions or additions that qualify as non-routine adjustments.

Since the inception of incentive tolling arrangements in 1995, through the cost performance sharing mechanism of the ITS, after-tax benefits by Enbridge and its customers of $96.8 million have been shared approximately 53% and 47%, respectively. Customers also have realized an additional after-tax benefit of $7.9 million through the power guarantee mechanism of the ITS.

Athabasca System

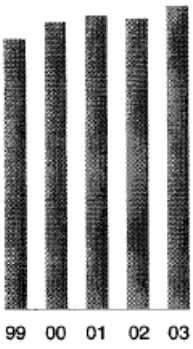
In 2003, earnings on the Athabasca System were $3.6 million higher than 2002, primarily due to a full year of earnings from the addition of the MacKay River lateral lines in late 2002. This was further enhanced by the development and commencement of operations, in November 2003, of cavern facilities to provide crude oil storage services. These facilities are located near Enbridge's main pipeline terminal at Hardisty, Alberta, and are jointly owned by Enbridge and an industry partner. The facilities have storage capacity approximating 3.1 million barrels, all of which have been fully subscribed to under a long-term fee-for-service agreement with a major energy producer.

In 2002, the construction of additional tankage and terminal facilities at the Athabasca terminal in Fort McMurray increased the investment base resulting in higher earnings than in 2001.

The Company has a long-term contract with the major shipper on the Athabasca System. Earnings are recognized based on the contract terms negotiated with the major shipper. Differences between actual cash tolls and toll revenue as determined under the contract is recognized in the period. The deferred amounts will be collected over the term of the contract.

Deliveries[1]

(thousands of barrels per day)



99	1,942
00	2,072
01	2,109
02	2,088
03	2,189

1 Includes deliveries by the 12.2% owned Lakehead System

NW System

Earnings in the last three years from the NW System have been consistent and reflect the effect of a declining rate base. The declining rate base was offset by cost savings that generated incentive earnings in 2002 and 2001. 2003 does not include an incentive component as 2003 was a rebasing year. Earnings are based on an agreement with the primary shipper and are a product of a deemed common equity ratio of 55% and the NEB multi-pipeline rate of return on common equity, plus any incentive cost savings.

Saskatchewan System

The earnings decrease noted in the Saskatchewan System of $3.3 million from 2002 is due to the Company's sale of this asset to EIF effective June 30, 2003.

Feeder Pipelines and Other

The earnings decrease in Feeder Pipelines and Other primarily reflects a provision for costs associated with toll complaints on Frontier. Business development costs were also higher in 2003 due to the continuing review of a number of liquids pipelines opportunities. Other factors contributing to the earnings variance include lower tolls on the Frontier Pipeline while the prior year included a positive revenue adjustment on the Toledo Pipeline.

Outlook

Enbridge System

The NEB approved the facilities application for construction of Phase III of the Terrace Expansion Project in Canada in April 2002. Phase III involved construction of 176 kilometres (110 miles) of 914-millimetre (36-inch) pipeline on the Lakehead System between Clearbrook, Minnesota and Superior, Wisconsin and pumping additions in both Canada and the United States. Phase III increased capacity by approximately 140,000 barrels per day when it was placed into service on April 1, 2003 and was requested by shippers to handle anticipated increases in oil sands volumes in the next few years.

Volumes transported are expected to increase in 2004 due to continuing increases in production from the oil sands region of Alberta. Oil sands production growth is more than offsetting declines in the Western Canadian Sedimentary Basin (WCSB) conventional production. Fluctuations in volumes do not impact the majority of net earnings from the Enbridge System due to provisions in the ITS.

The ITS allows Enbridge and its customers to share in cost savings achieved. The Company will continue to focus on operational excellence in order to ensure continued savings for customers and increased returns for shareholders.

Enbridge Athabasca System

The Enbridge Athabasca System is the only liquids pipeline directly linking both the Athabasca and Cold Lake oil sands deposits with the pipeline transportation hub at Hardisty, Alberta. With a design capacity of 570,000 barrels per day, the pipeline is well positioned to carry more of the region's oil sands and heavy oil production in the future.

Earnings from the Athabasca System are expected to increase in 2004 as a result of a full year of operations from underground storage and other facilities placed into service in 2003.

Supply

Liquids supply growth from the WCSB is expected to continue to increase over the next 10 years. The NEB's latest estimates for 2003 project WCSB production growth of oil sands and heavy oil volumes of 120,000 barrels per day over 2002 volumes, offset by a decline in conventional production of 35,000 barrels per day. The net increase in WCSB production of 85,000 barrels per day over 2002 levels translates into the highest level of production ever achieved by the WCSB and reflects the growth in bitumen and upgraded synthetic production.

Remaining established conventional oil reserves in Western Canada were estimated to be five billion barrels in 2002. During 2002, approximately 65% of volumes produced were replaced with reserve additions. Remaining established reserves from oil sands currently stand at 174 billion barrels, with nearly four billion barrels having been produced to date. According to the Oil and Gas Journal's Worldwide Look at Reserves and Production, Canada's reserves represent 14% of world oil reserves, second only to Saudi Arabia in size. [1]

Capital Expenditures

Liquids Pipelines expects to spend approximately $80 million in 2004 for ongoing capital improvements and core maintenance capital projects relating to the main pipeline system. Additional expenditures of US$20 million are also expected in 2004 to reverse the flow of the Cushing-to-Chicago Pipeline System, which was acquired in 2003. At that time, the final payment of US$65 million will be paid to the vendor.

Business Risks

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 for oil sands projects, the price of natural gas used for steam production, and the price of crude oil. Oil targeted drilling licenses in Western Canada increased 25% in 2003 from 2002. This strong drilling activity, along with the start-up of Shell's Athabasca oil sands project, resulted in significant production growth over 2002. For 2004, growth is expected to continue with full year production from Shell's Athabasca oil sands project and expansions at Cold Lake, and the completion of expansions at Syncrude and Suncor.

1 CAPP Statistical Handbook — current year

Historically, refiners in the U.S. Midwest have utilized large volumes of Western Canadian light crude versus other imported crude. Line 9 transports offshore crude to Ontario and is owned by Enbridge. Volumes on Line 9 have displaced some Canadian and U.S. domestic deliveries in the Ontario market, requiring an increase in deliveries to the U.S. Midwest, which has limits on the volume of Canadian crude which can be readily absorbed.

Following Canada's ratification of the Kyoto Protocol, Enbridge has continued to assess the potential impact on oil sands investment. Moody's Investors Service recently surveyed oil sands operators and concluded that Kyoto is expected to have a minimal effect on the development of Alberta's oil sands resource. Enbridge is encouraged by this conclusion as it supports the sustainability of supply for liquids pipelines.

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. To the extent the NEB rate of return fluctuates, a portion of the earnings of the Enbridge System changes. The Company believes that regulatory risk has been reduced through the negotiation of long-term agreements, such as the ITS, with its customers.

Competition

The Enbridge System transported approximately 67% of total Western Canadian crude oil production in 2003 and provides approximately 77% of the capacity for the transportation of Western Canadian crude oil out of Canada. Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, and proximity to markets. TransMountain Pipeline and Express Pipeline, as well as other common carriers, can be used by 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 elsewhere than delivery points 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.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines. Unused capacity on the Athabasca System should be more competitive than a new pipeline. Due to the size of the oil sands reserves, competitive pressures to provide economical transportation service continue.

Environment and Safety

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. These systems reflect industry best practices and are aligned with the ISO 14001 standard and the BSI-OHSAS 18001 specification for environmental, health and safety management systems. Regular reviews and audits are conducted to assess compliance with legislation and company policy.

Pipeline leaks are an inherent risk of operations. 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.

GAS PIPELINES

Financial Results

(millions of Canadian dollars)	2003	2002	2001
Alliance Pipeline (US)	**40.3**	19.6	19.0
Alliance Pipeline (Canada)	**19.6**	21.1	18.6
Vector Pipeline	**10.2**	7.1	3.9
	70.1	47.8	41.5

Business Activities

Gas Pipelines activities consist of investments in the Alliance and Vector pipelines, accounted for under proportionate consolidation.

Enbridge owns a 50.0% interest in Alliance Pipeline (US), the U.S. portion of a 3,000-kilometre (1,800-mile) pipeline that transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois. The Company provides operating services to and holds a 60% investment in Vector, which transports natural gas from Chicago to Dawn, Ontario. Both Alliance and Vector commenced operations in December 2000. Alliance and Vector have the capacity to deliver 1.55 billion cubic feet per day (bcfd) and 1.0 bcfd, respectively.

Alliance Pipeline (Canada) was sold to the Enbridge Income Fund effective June 30, 2003. Prior to this disposition, the Company had increased its ownership interest from 21.4% in 2001 to 37.1% in late 2002 and up to 50% in 2003.

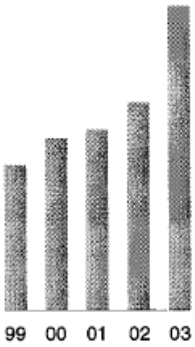
Results of Operations

Earnings from Gas Pipelines were $70.1 million for the year ended December 31, 2003, an increase of $22.3 million from 2002. The higher earnings were primarily due to additional interests acquired in Alliance and Vector in 2003, partially offset by the sale of the Company's interest in the Canadian portion of Alliance Pipeline in the second quarter.

Earnings were relatively constant between 2002 and 2001 with the exception of higher earnings from the Vector Pipeline.

Gas Pipelines Earnings

(millions of dollars)



99	33.2
00	39.6
01	41.5
02	47.8
03	70.1

Alliance Pipeline (US)

The increase in earnings of $20.7 million from Alliance Pipeline (US) in 2003, compared with 2002, reflects the acquisition of additional ownership interests of 1.1% in March 2003, 10.7% in April 2003, and 1.1% in October 2003. The Company's current ownership is 50.0%.

In late 2002, the Company acquired an additional ownership interest of 15.7%. However, due to the timing of the transaction, there was no significant effect on 2002 earnings in comparison to 2001.

Alliance Pipeline (Canada)

Alliance Pipeline (Canada) is included in the results of EIF, in the Sponsored Investments segment, effective June 30, 2003. Prior to its sale to EIF, the Company's ownership interest in Alliance Pipeline (Canada) had increased from 21.4% to 50.0%.

Vector Pipeline

The contribution from Vector is $3.1 million higher in 2003, compared with 2002, as a result of increased volumes and transportation margins,

due to both colder than normal weather in Eastern Canada and higher storage injections. This is further enhanced by additional ownership interests of 15.0% acquired in the fourth quarter of 2003. The Company's current ownership is 60.0%.

Earnings in 2002 were $3.2 million higher than in 2001 as a result of a one-time adjustment to depreciation expense, reflecting a revision to depreciation rates to be consistent with the rates approved by the Federal Energy Regulatory Commission (FERC). In addition, an adjustment was booked in 2001 to reverse earnings that were over accrued in 2000.

Outlook

Earnings from Alliance Pipeline (US) and Vector should increase in 2004 as a result of Enbridge's higher ownership interest. There is no near-term requirement for further partner investment in either pipeline.

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. 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, Liquefied Natural Gas, and the Alaska North Slope/Mackenzie Delta are expected to alleviate supply concerns. This is expected to improve the stability of natural gas prices and provide a more favourable pricing structure that will facilitate further growth in the power generation market.

Business Risks

Alliance and Vector are regulated federally and are subject to regulatory risk. The Company believes that this risk has been mitigated through the execution of long-term contracts with customers. Currently, pipeline capacity out of the WCSB exceeds supply. Alliance has been unaffected but Vector has not fully contracted its capacity and, as a result, is negatively impacted by the basis (location) differential between Chicago and Dawn, Ontario.

Exposure to Shippers

Alliance is highly dependent upon the shippers for revenues from contracted capacity on the Alliance system. 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 and could impair the ability of Alliance to meet its debt obligations and make distributions to its limited partners. A prolonged economic downturn in the energy industry, among other things, could impact the ability of some or all of the shippers to fulfill their obligations under the transportation contracts. To reduce this risk, Alliance has put certain controls in place to monitor the creditworthiness of each shipper.

Pipeline Operating Risk

As with any comprehensive pipeline system, the operation of Alliance and Vector involves many risks, including: 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 respective systems. The occurrence or continuance of any of these events could increase the cost of operating Alliance or Vector and reduce transportation capacity, thereby impacting earnings. Risks of substantial costs and liabilities, including those from leaks and explosions, are inherent in pipeline operations and there can be no assurance that significant costs and liabilities will not be incurred, including those relating to claims for damages to property and persons.

SPONSORED INVESTMENTS

Financial Results

(millions of Canadian dollars)	2003	2002	2001
Enbridge Energy Partners	**27.3**	19.5	12.5
Enbridge Income Fund	**17.6**	—	—
Enbridge Midcoast Energy	**—**	5.5	9.5
Gain on sale of assets to Enbridge Income Fund	**169.1**	—	—
Writedown of Enbridge Midcoast Energy assets	**—**	(82.2)	—
Dilution gains	**20.3**	6.1	15.2
	234.3	(51.1)	37.2

Business Activities

Sponsored Investments includes the Company's ownership interests in the operations of EEP and EIF. Enbridge operates the assets of both investments.

Enbridge has an effective 12.2% ownership interest (2002 – 14.1%, 2001 – 13.6%) in EEP. This ownership interest represents the Company's direct investment in EEP of 9.1% and an indirect investment of 3.1% through the Company's 17.2% ownership interest in Enbridge Energy Management (EEM). Enbridge, as the general partner of EEP, receives incentive income based on the level of quarterly cash distributions. EEP owns the Lakehead System, a feeder pipeline in North Dakota, the Enbridge Midcoast Energy (Midcoast) assets, and natural gas gathering and processing assets in East Texas (East Texas System).

Effective June 30, 2003, Enbridge sold its 50% interest in the Canadian portion of Alliance Pipeline and 100% ownership of Enbridge Pipelines (Saskatchewan) Inc. to EIF. For the period prior to this sale, the operating results of Alliance Canada are included in Gas Pipelines, and the operating results of Enbridge Pipelines (Saskatchewan) Inc. are included in Liquids Pipelines. Thereafter, the operating results of these assets are included in EIF, which is a component of this segment.

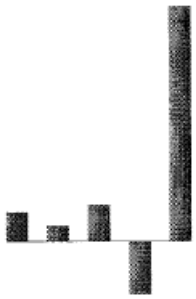
In October 2002, Enbridge sold the United States assets of Midcoast to EEP. From May 2001 until October 2002, Enbridge owned 100% of Midcoast. The results of operations of Midcoast, in the preceding table, relate to the period when the assets were wholly-owned.

Results of Operations

For the year ended December 31, 2003, earnings were $234.3 million compared with a loss of $51.1 million for 2002. The current year results include an after-tax gain of $169.1 million on the sale of the Company's interests in Alliance Pipeline (Canada) and Enbridge Pipelines (Saskatchewan) Inc. to EIF. The 2003 results also include dilution gains of $20.3 million, compared with $6.1 million in 2002. This reflects two unit issuances by EEP in 2003, compared with only one in the prior year.

Sponsored Investments Earnings

(millions of dollars)



99	30.4
00	16.3
01	37.2
02	(51.1)
03	234.3

Excluding the impact of these gains, earnings in this segment increased $102.1 million from 2002. A significant portion of this year-over-year change is due to an $82.2 million writedown recorded in 2002 on the sale of the Midcoast assets. The remainder of the $19.9 million increase is attributed to the creation of EIF, effective June 30, 2003, and incremental earnings in EEP from increased throughput on the Lakehead and North Dakota systems.

For the year ended December 31, 2002, earnings from Sponsored Investments decreased by $88.3 million from $37.2 million from 2001. The 2002 results included an $82.2 million writedown on the sale of the Midcoast assets. Excluding this writedown, earnings for 2002 were $6.1 million lower than 2001. Increased earnings from EEP resulted from the acquisitions of the North Dakota and East Texas Systems, and the Midcoast assets. These additional earnings were more than offset by lower earnings from Midcoast prior to its sale and higher dilution gains in 2001.

In October 2002, the Company closed the sale of the United States assets of Midcoast to EEP for consideration of US$820.0 million, including cash and the assumption of affiliate debt. Concurrent with the sale transaction, EEM, a subsidiary of Enbridge, completed an initial public offering of 9,000,000 shares representing limited liability company interests with limited voting rights. The net proceeds from the offering were used to purchase i-units, a new class of limited partnership interests, from EEP. The proceeds from the i-units were used to finance a portion of the acquisition cost of the assets. In connection with the offering, Enbridge purchased 17.2% of the EEM shares, increasing its effective ownership in EEP to 14.1% from 12.9%. EEM has no assets or operations other than those related to the interest in EEP and, by agreement, will manage the business and affairs of EEP.

Enbridge Energy Partners

Equity earnings in EEP improved in 2003, compared with 2002, due to higher incentive earnings earned by Enbridge as the general partner and improved results from the Lakehead System. The increased earnings also reflect incremental earnings from EEP's acquisition of the Company's Midcoast assets in October 2002, and increased throughput on the Lakehead and North Dakota systems.

The increased contribution from EEP in 2002 compared with 2001 resulted from the acquisitions of the North Dakota and East Texas Systems in 2001, which contributed a full year's earnings in 2002. The acquisition of the Enbridge Midcoast Energy assets also increased earnings in the fourth quarter of 2002.

Enbridge Midcoast Energy

Midcoast was sold to EEP in October 2002. Enbridge purchased Midcoast in May 2001 for cash consideration of $561.8 million and the assumption of long-term debt. Earnings from Midcoast in 2002 were $5.5 million, a decrease of $4.0 million from the prior year. While 2002 results reflected improved operating performance, earnings were more than offset by adjustments related to 2001 that were recorded in 2002 and working capital and other closing adjustments identified prior to the disposition. Earnings for 2002 are for the period prior to the October 2002 disposition. Earnings for 2001 represent earnings from the May 2001 date of acquisition.

In March 2002, the Company acquired natural gas gathering and processing facilities in northeast Texas for approximately $290 million. These assets were included with Midcoast and were part of the October 2002 sale to EEP.

Enbridge Income Fund

In June 2003, the Company formed EIF. On formation, EIF acquired the Company's 50% interest in the Canadian segment of Alliance Pipeline together with its 100% interest in the Saskatchewan System. EIF has positively contributed to the Company's earnings in the year.

Outlook

Enbridge Energy Partners

Earnings from the Lakehead System and certain of the gas gathering assets are volume-sensitive and expected increases in volumes should have a positive impact on EEP's earnings.

EEP is also expected to experience growth as it reaches new markets through assets acquired in 2003. Effective December 31, 2003, EEP closed its acquisition of the North Texas System, a collection of natural gas gathering and processing assets in North Texas. The system primarily serves the Fort Worth Basin, including growing production from the Barnett Shale zone.

Also in the fourth quarter of 2003, EEP announced that it had signed an agreement to acquire crude oil pipeline and storage systems in the U.S. Midcontinent. The assets being acquired serve refineries in the Midcontinent from the Cushing, Oklahoma hub and consist of approximately 615 miles (990 kilometres) of active crude oil pipelines and 9.5 million barrels of storage capacity. Included in these assets are the 433-mile (697-kilometre) Ozark Pipeline, which currently transports 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois; the 47-mile (76-kilometre) West Tulsa Pipeline, which currently transports 55,000 barrels per day to two refineries in Oklahoma; and the Shell storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity. Most notably, though, this acquisition diversifies the Company's sources of income from crude oil transportation and storage services, reducing its dependence on production from the WCSB.

Enbridge Income Fund

Enbridge Income Fund will continue to focus its efforts in 2004 on managing system assets and infrastructure, and further developing its operational procedures and processes with a view to maximizing available transportation capacity and the competitiveness of its tolls. The Fund remains confident that it will generate built-in, predictable growth in cash flow from its assets in order to provide modest but regular on-going distribution increases, supplemented with some acquisition-based growth.

Business Risks

All of the Company's operations in Sponsored Investments are carried out through EEP and EIF and therefore the risks are limited to the percentage investment that the Company has in each entity.

Enbridge Energy Partners

Supply and Demand

The operation of the Lakehead System depends to a large extent on the volume of products transported on its pipeline systems. Decreases in the volume of products transported by the Partnership's systems, whether caused by supply or demand factors, can directly affect EEP's revenues and results of operations. The volume of shipments on the 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. EEP expects future increased supplies to come from the oil sands projects in Alberta. In addition, future plans to expand into the southern United States will increase demand for Western Canadian crude.

Supply is dependent upon a number of variables including the level of exploration, drilling, reserves and production of natural gas, crude oil and other liquid hydrocarbons. It is also impacted by the accessibility, price and quality of commodities available from alternate Canadian and U.S. sources, and the regulatory environments in Canada and the U.S., including the continued willingness of the governments of both countries to permit the export of natural gas, crude oil, and other liquid hydrocarbons from Canada to the United States on a commercially acceptable basis.

Certain of 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.

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. Gas gathering currently is not subject to active regulation. Several of EEP's assets are regulated by FERC and their revenues could decrease if tariff rates were protested.

Market Price Risk

EEP's business is subject to commodity price risk for natural gas costs and natural gas liquids. Historically, these risks have been managed by using derivative financial instruments, fixing the prices of natural gas and natural gas liquids.

Enbridge Income Fund

Risks within EIF relate to Alliance Canada and the Saskatchewan System. Risks for Alliance Canada are similar to those identified under the Gas Pipelines segment, which includes the U.S. portion of the Alliance System. Below are risks identified within EIF directly related to the Saskatchewan System.

Supply and Demand

The majority of the volumes shipped on the Saskatchewan and Westspur pipeline systems are transported on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

Competition

The Saskatchewan System faces competition in pipeline transportation from other pipelines, as well as other forms of transportation, most notably trucking. For the Weyburn and Virden pipeline systems, which use market based tolls, the cost of alternative transportation options affects the rates that can be charged for transportation service on these pipelines. The cost of alternative transportation options also provides a competitive force on the Saskatchewan System's cost of service based pipelines, the Saskatchewan and Westspur pipeline systems. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers with the effect of forcing the Saskatchewan System, for commercial reasons, to lower the transportation rates to avoid losing shippers, thereby reducing the Saskatchewan System's cash flow from transportation services.

GAS DISTRIBUTION AND SERVICES

Financial Results

(millions of Canadian dollars)	2003	2002	2001
Enbridge Gas Distribution	**103.0**	85.3	156.1
CustomerWorks/ECS	**16.9**	10.7	14.3
Noverco	**24.2**	20.6	16.3
Other Gas Distribution	**6.6**	6.2	5.5
Enbridge Gas New Brunswick	**4.4**	3.6	2.3
Gas Services	**(5.9)**	(7.8)	(5.3)
Aux Sable	**(6.9)**	(3.1)	(6.2)
Other	**11.3**	8.8	6.6
	153.6	124.3	189.6

Business Activities

Gas Distribution and Services primarily includes the gas distribution operations of Enbridge Gas Distribution (EGD), CustomerWorks/ECS, the Company's investment in Noverco, and other gas distribution activities in smaller franchise areas. This segment also includes the gas services business, which manages the Company's merchant capacity commitments on Alliance and Vector; the Company's investment in Aux Sable, which is accounted for through proportionate consolidation; as well as the equity investment in AltaGas Services.

EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.7 million customers in Central and Eastern Ontario, Southwestern Quebec and parts of Northern New York State. Its operations in Ontario are regulated by the Ontario Energy Board (OEB).

CustomerWorks/ECS includes the operations of CustomerWorks LP, whose operations commenced on January 1, 2002, and provides services covering the entire meter-to-cash process, including many of the services which, until then, were provided by Enbridge Commercial Services (ECS). The results of ECS in 2002 and 2001 also include information technology and fleet services, which were rebundled into EGD in the fourth quarter of 2002. CustomerWorks was formed by Enbridge and Terasen and serves over 3.5 million customers including those of Terasen's and Enbridge's gas distribution operations. 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 preference shares. Noverco is a holding company that owns an approximate 75% interest in Gaz Metro Limited Partnership, a gas distribution company operating in the province of Quebec and the state of Vermont, which has a 50% interest in TQM Pipeline, a pipeline transporting natural gas in Quebec.

The Company owns 63% of and operates Enbridge Gas New Brunswick (EGNB), the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 2,300 customers. Over 200 kilometres (124 miles) of distribution main has been installed with the capability of attaching 6,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Results of Operations

Earnings were $153.6 million for the year ended December 31, 2003, compared with $124.3 million in 2002. Higher earnings were attributable to colder than normal weather experienced in the EGD franchise area in 2003, further aided by a decrease in losses from Gas Services and an increased contribution from CustomerWorks/ECS.

Earnings from Gas Distribution and Services were $124.3 million for the year ended December 31, 2002, compared with $189.6 million in 2001. The results reflect strong operating performance from EGD, more than offset by a smaller positive impact of tax rate reductions in 2002 than in 2001. Earnings from Noverco were also lower in 2002 due to the positive effect of tax rate reductions on earnings in 2001.

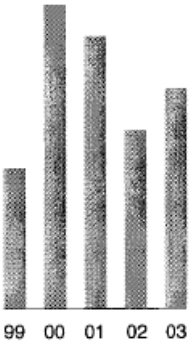
Enbridge Gas Distribution

Earnings from EGD increased by $17.7 million in 2003 from 2002. The increase was due to higher gas distribution margins caused by increased distribution volume resulting from colder weather. This is partially offset by a $26.0 million regulatory receivable writedown related to a prior year, a $7.1 million OEB gas cost disallowance related to long-term transportation contracts and a $4.6 million OEB outsourcing disallowance. Had EGD experienced normal weather in its franchise area, reported net earnings would have decreased by approximately $46.1 million after tax. Normal weather is the weather forecast by EGD, 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. The effect of weather is measured by degree-day deficiency and is calculated by accumulating, from October 1, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. 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 uses the degree-days from the most recent years to determine the estimate. This weather-normalized adjustment is consistent with the manner in which EGD calculates degree-days for regulatory purposes.

The results for 2002 decreased by $70.8 million from 2001 due to the effect of the significantly warmer than normal weather in 2002. On a weather-normalized basis, earnings would have been higher by $29.3 million after tax while, for 2001, earnings would have decreased $5.0 million. In addition, 2001 included the positive impact of tax rate reductions of $45.0 million.

Gas Distribution and Services Earnings

(millions of dollars)



99	97.7
00	211.7
01	189.6
02	124.3
03	153.6

Prior to 2000, EGD's rates were typically determined using a cost-of-service methodology that allowed the revenues to be set to recover EGD's forecast costs. 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 the investment in all assets used in gas distribution, storage and transmission, as well as an allowance for working capital. A requested increase in rates to recover forecast costs reflects a revenue deficiency, while a reduction in rates reflects a revenue sufficiency. Under cost of service, it is the responsibility of EGD to demonstrate to the OEB the prudence of the costs it is forecasting to incur over the year. EGD does not profit from the sale of the natural gas commodity.

During the fiscal periods 2000 to 2002, EGD operated under a targeted Performance-Based Regulation plan (PBR plan). The PBR plan used a formula to calculate the level of operation and maintenance costs recoverable in rates. During the PBR period, the Company was allowed to retain any savings realized if it achieved lower operation and maintenance expenses than those calculated under the formula.

EGD's 2003 rates were established pursuant to the cost-of-service methodology.

The allowed rate of return on common equity for EGD is based on the yield on Canadian government long-term bonds. For 2003, the allowed rate of return was 9.69% (2002 – 9.66%, 2001 – 9.54%) on a deemed common equity ratio of 35.0%.

Over the last four years, EGD added 209,000 customers, including over 50,000 customers (net) in 2003. EGD services approximately 95% of residential space heating in its franchise area. This growth was attributable to the continued preference for natural gas among homeowners, builders and business operators, primarily because of the ongoing price advantage of natural gas and environmental benefits over other forms of energy. The residential construction market showed continued strength in 2003, which fueled demand for natural gas used in space and water heating. In addition, builders are increasingly using portable natural gas-fired heaters during cold weather construction.

CustomerWorks/ECS

The contribution from CustomerWorks/ECS was $16.9 million for the year ended December 31, 2003, an increase of $6.2 million compared with the prior year. The main component of these earnings in 2003 is the contribution from CustomerWorks as the primary operations of ECS were rebundled into EGD at the end of 2002. In 2002, earnings from CustomerWorks were affected by activity levels, including customer service calls, which were lower due to warmer weather. In 2003, earnings reflect higher weather-related customer service call volumes and growth in the CustomerWorks customer base.

Lower earnings from CustomerWorks/ECS in 2002, compared with 2001, reflect the positive impact of tax rate reductions in 2001 and the transfer of a vast majority of the remaining ECS operations into Enbridge Gas Distribution in the fourth quarter of 2002.

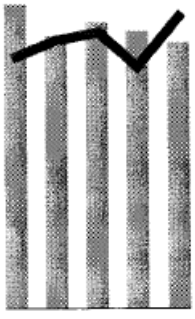
Noverco

The contribution from Noverco was $24.2 million in 2003, compared with $20.6 million in 2002. The increase is due to the 2003 results including a $6.0 million dilution gain, resulting from a Gaz Metro Limited Partnership unit issuance that Noverco did not participate in. Equity earnings from Noverco in 2002 were higher than 2001, mainly due to lower financing costs and higher incentive earnings.

Variations from normal weather 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 preference share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%. The weighted average dividend yield on the preference shares, which is reset annually, was approximately 10% for each of the last three years.

Energy Distribution Degree Day Deficiency

(degrees Celsius)



	Forecast	Actual
99	4,060	3,460
00	3,629	3,569
01	3,816	3,766
02	3,700	3,362
03	3,565	4,029

Enbridge Gas New Brunswick

Earnings from Enbridge Gas New Brunswick improved in 2003 due to increased customer connections. Earnings were better in 2002 than 2001 due to a full year of operations.

Gas Services

Gas Services experienced a loss of $5.9 million for the year ended December 31, 2003, compared with a loss of $7.8 million in 2002. The improvement is due primarily to the commencement of fee-based gas service management contracts with certain U.S.-based companies in late 2002 and increased demand for natural gas and associated transmission services, reducing merchant capacity losses on Alliance and Vector. Losses in 2002 were $2.5 million higher than those in 2001 due to the reduced basis differentials between Alberta and Chicago, and between Chicago and Dawn, Ontario, which increased the losses on the Company's Alliance and Vector merchant capacity. The basis differential is the cost of transportation between natural gas hubs and determines the revenue that can be obtained from merchant transportation capacity.

Aux Sable

Enbridge owns a 42.7% interest in the Aux Sable facilities, which process natural gas delivered through Alliance. As the gas transported by Alliance is liquids-rich, it must be processed prior to delivery to other systems. Aux Sable commenced operations in December 2000 and has the capacity to process up to 1.6 bcfd of natural gas. In 2003, the loss from Aux Sable was $6.9 million, a weakening of $3.8 million from the 2002 loss of $3.1 million. The additional loss reflects the combined effect of higher natural gas prices and lower ethane prices relative to 2002, most significantly during the second quarter of 2003. The results from Aux Sable in 2003 also reflect the increase in ownership interest from 30.9% to 42.7% offset by lower depreciation as the acquisition of the additional interest was at a discount to the book value.

Losses in 2002 were lower than those in 2001 by $3.1 million due to better margins between natural gas liquids and natural gas throughout 2002. The Company's ownership interest in Aux Sable increased from 21.4% to 30.9% in the fourth quarter of 2002.

Outlook

Enbridge Gas Distribution

2004 Rate Application

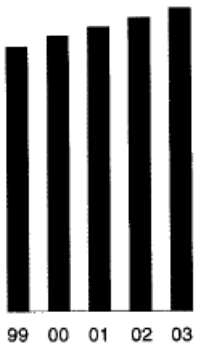
EGD filed its fiscal 2004 rate application with the OEB in April 2003. EGD's objective was to return to an appropriate regulatory schedule whereby rates would be set prospectively. EGD's 2004 rate application requested that rates for 2004 be set by increasing 2003 rates by 90% of the forecast Ontario consumer price index, that being an increase of 1.8%. EGD reached a partial settlement with certain intervenors to accept this innovative approach to rate setting.

The OEB accepted the negotiated settlement proposal for the 2004 rates on September 4, 2003, thus allowing rates to be in place for the start of the 2004 fiscal year. The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a weather normalized basis exceed the benchmark return on equity (ROE), these excess earnings would be shared on a 50/50 basis between the ratepayers and Enbridge.

Acceptance by the OEB of EGD's 2004 Rate Application was successful in returning the rate-making schedule to a prospective basis by setting 2004 rates as a function of the forecast consumer price index for the fiscal 2004 year. EGD filed the 2005 Rate Application with the OEB in December 2003. The hearing is expected to be held in June 2004.

Energy Distribution Number of Active Customers

(thousands)



99	1,466
00	1,520
01	1,571
02	1,623
03	1,679

Review of OEB Formula for Setting ROE

In September 2003, the OEB completed a hearing to review and consider possible revisions to the current ROE formula that is adjusted by any change in the long-term Canadian bond yield. EGD filed evidence to propose a ROE for 2004 of 11.2%. The increase in the requested ROE reflects EGD's belief that this is more representative of a risk-adjusted return within the North American equity markets. A decision was issued on January 16, 2004, which dismissed the application and confirmed the use of the existing formula. A ROE of 9.69% is embedded in the 2004 rates.

Legislative Change and Future Regulatory Direction

On August 1, 2003, the Ontario Energy Board Consumer Protection and Governance Act, 2003 was proclaimed, providing a new mandate for the OEB. The legislation provides for improved regulatory processes, performance measurement and reporting by the OEB, as well as the establishment of the OEB as a self-financing Crown Agency.

Gas Distribution Access Rule

The OEB, pursuant to the Energy Competition Act, has undertaken the development of a Gas Distribution Access Rule (GDAR). The stated purpose of the GDAR is to establish rules governing natural gas distributors' conduct in relation to gas marketers and to establish conditions of access to distribution services. The OEB issued the final version of the GDAR in December 2002. Despite EGD's arguments with respect to the GDAR's position on customer mobility and billing options, the GDAR mandates that distributors, including EGD, provide gas marketers with the option to consolidate the gas distribution charges to consumers on the marketers' own bill, forcing the distributor to appoint the marketer as its billing agent. EGD would have to undertake extensive system changes and negotiate new contractual arrangements in order to effect the GDAR directives. Accordingly, EGD and Union Gas Limited both appealed the so-called vendor consolidated billing aspects of the GDAR to the Ontario Divisional Court. The Ontario Divisional Court heard the appeals in August 2003 and in September 2003, the Court issued a decision dismissing the appeals and upholding the OEB's jurisdiction to enact the vendor consolidated billing portions of the GDAR. Both EGD and Union Gas Limited, Ontario's other principal gas distributor, have been granted leave from the Ontario Court of Appeals to hear an appeal of the Ontario Divisional Court's decision.

In the interim, the Company is working closely with the OEB and gas marketers to resolve other outstanding GDAR implementation issues.

Enbridge Gas New Brunswick

Customer attachment to the EGNB system has been slower than expected. EGNB plans to increase the attachment rate by becoming actively involved in the sale of the natural gas commodity and the sale, installation and service of natural gas equipment to the residential and small commercial markets. This "bundled" approach was approved by the provincial legislation during 2003.

Capital Expenditures

Capital expenditures in 2004 for the Gas Distribution and Services business are expected to be approximately $287 million. The majority of the expenditures relate to expansion of and core maintenance on the EGD system. It is anticipated that these additions will be financed through internal funds as well as short and medium-term borrowings.

Business Risks

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 timely and adequate rate relief, accuracy in forecasting distribution volume, and, most importantly, achieving the forecast natural gas distribution volume. The new Ontario government's intentions with respect to the current freeze in electricity prices, which expires in 2006, and the direction of natural gas prices in the medium to long term will impact EGD's competitiveness in the energy market.

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 rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather; economic conditions; pricing of competitive energy sources; and the number of customers.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 77% (2002 – 74%) 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.

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. In addition, technology issues combined with increased costs of residential natural gas water heaters may pressure EGD's market share for natural gas water heaters.

Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the 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. The timing of gas sales is also a factor, as higher rates are charged during the winter season than during the summer season.

Rate Relief

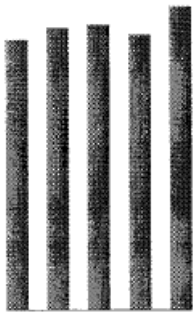
Through the regulatory process, the OEB approves the return on equity that EGD is allowed to earn, in addition to various other aspects of utility operations.

Rate relief could also be sought 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 sale 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. EGD monitors the balance and its potential impact on ratepayers and requests, on a quarterly basis, interim rate relief that will allow EGD to recover or refund the gas commodity cost differential.

Energy Distribution Volume of Gas Distributed

(billions of cubic feet)



99	402
00	421
01	427
02	410
03	458

Forecasting Accuracy

Forecasting accuracy is a risk since rate applications are made or 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. Consequently, the forecasting process ensures that any changes in cost of service, regardless of whether they are caused by inflation or by level of business activity, would be recovered in new rates approved for that fiscal year based on the anticipated distribution volume.

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 will continue to be exposed to the effect of unfavorable spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. Earnings would be negatively impacted by a decrease in the spread and positively impacted by an increase in the spread. Aux Sable has initiated a hedging program which will mitigate its earnings volatility.

INTERNATIONAL

Financial Results

(millions of Canadian dollars)	2003	2002	2001
OCENSA/CITCol	**32.3**	35.3	35.1
CLH	**46.3**	33.3	–
Jose Terminal and Other	**(6.3)**	(0.6)	0.5
	72.3	68.0	35.6

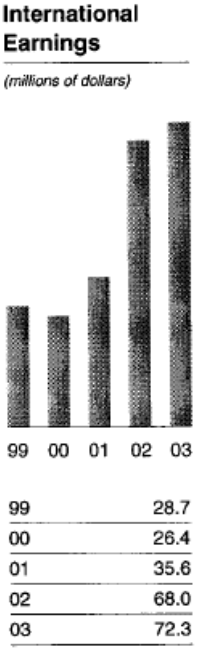
Business Activities

International includes earnings from the investments in OCENSA, a crude oil pipeline in Colombia, and CLH, Spain's largest refined products transportation and storage business. Earnings also include fees earned from technology and consulting services provided by Enbridge Technology Inc.

OCENSA is a cost investment on which the Company earns a stated return and which contributes a significant portion of the earnings. The Company also has responsibility for the operations of the pipeline, through CITCol, and earns a fee for this service, which includes incentive earnings for operating performance.

The Company owns a 25% interest in CLH of Spain. The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network throughout Spain. Earnings are based on a fee for service and are dependent on throughput volumes and storage levels.

As a result of a breach of the Jose Terminal operating agreement by PDVSA, the Venezuelan state oil company, the SWEC Partnership, in which the company holds a 45% ownership, has filed a notice of contract termination and has filed for international arbitration, as provided for in the operating agreement. The company ceased recognition of earnings commencing February 1, 2003. Other is primarily administration and business development costs and the results of the Technology business.



Results of Operations

Earnings increased by $4.3 million to $72.3 million in 2003 primarily as a result of higher earnings from CLH, which was due to increased volumes and the impact of a stronger Euro, partially offset by a reduction in marine fleet revenues due to the scheduled retirement of certain ships. These increased earnings were partly offset by the termination of the Jose Terminal operating agreement and lower incentive earnings from CITCol.

Earnings in 2002 increased by $32.4 million to $68.0 million. The increase was primarily due to the acquisition of a 25% interest in CLH during the first quarter of 2002.

Outlook

The International business will continue to focus on select countries in key regions based on global trends in supply and demand. In addition, opportunistic acquisitions will be assessed based on risk and reward. The technology and consulting business provides support in connection with identification and development of equity participation projects.

Increased international asset rationalization, the changing corporate strategies of multinationals, and the privatization of energy transportation activities in focus regions should continue to present grassroots investment and acquisition opportunities. Opportunities will be evaluated against

the Company's strict investment criteria. Latin America and Western Europe are key regions of interest. Enbridge plans for the International segment to contribute approximately 15% of the Company's earnings over the long term.

Business Risks

The International business is subject to risks related to political and economic instability, currency volatility, market 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, operation of the assets, regular analysis of country risk, as well as foreign currency hedging and insurance programs.

CORPORATE

(millions of Canadian dollars)	2003	2002	2001
Corporate	**(76.6)**	(44.4)	(55.1)

The Corporate segment includes business development activities not attributable to a specific business segment, corporate financing costs and other corporate activities.

Corporate costs amounted to $76.6 million in 2003, an increase of $32.2 million from 2002. During 2003, the Company incurred slightly lower financing costs more than offset by various negative factors in the fourth quarter including increased business development costs, an expense for stock-based compensation, and other corporate costs primarily relating to prior year business dispositions and final settlements. The Company adopted the fair-value based method of accounting for stock-based compensation effective January 1, 2003.

Corporate costs totalled $44.4 million in 2002, compared with $55.1 million in 2001. In 2002, Corporate included an after-tax gain on the sale of securities of $17.8 million and lower financing costs. Preferred securities distributions increased in 2002 due to the new issue in February 2002.

DISCONTINUED OPERATIONS

In January 2002, the Company announced the sale of the retail and commercial Energy Services business, including the water heater rental program, to focus on its core activities of energy transportation and distribution. The sale, for proceeds of $1 billion, was completed in the second quarter of 2002. This business included: the water heater rental program; retail appliance, fireplace and water heater sales and service; and mass market commercial plumbing, heating, ventilation and air conditioning, appliance repair and electrician contractor services in Canada and the United States.

Earnings from discontinued operations for the year ended December 31, 2002 were $242.3 million, compared with $45.3 million for 2001. The 2002 results included a gain on sale of $240.0 million. Earnings in 2001 included a full year's results of operations and $14.3 million related to the positive effect of income tax rate reductions.

CRITICAL ACCOUNTING POLICIES

Rate Regulation

The Company follows generally accepted accounting principles, which may differ for regulated operations from those otherwise expected in non-regulated businesses. These differences occur when the regulatory agencies render their decisions on rate applications and generally involve the timing of revenue and expense recognition to ensure that the actions of the regulator, which create assets and liabilities, have been reflected in the financial statements.

The accounting for these items is based on an expectation of the future actions of the regulator. For example, the Company does not record future income taxes related to its regulated operations as the taxes payable method is prescribed by the regulator for rate-making purposes and there is reasonable expectation that all such future income taxes will be recovered in rates when they become payable. Similarly, the deferral of differences between amounts included in rates and actual experience for specified expenses is based on the expectation that the regulator will approve the refund to or recovery from ratepayers of the deferred balance, normally in the following year.

If the regulator's 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.

LIQUIDITY AND CAPITAL RESOURCES

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities, and access to capital markets in Canada and the United States for the issuance of long-term debt, equity, or other securities is expected to be sufficient to satisfy liquidity requirements.

The Company continues to manage its debt-to-equity ratio to maintain a strong balance sheet. The debt-to-equity ratio at December 31, 2003, including short term borrowings, but excluding non-recourse short and long-term debt of its joint ventures, was 61.4%, compared with 64.4% at the end of 2002. The reduced leverage was primarily a result of the proceeds received on the sale of assets to EIF.

Operating Activities

Cash provided by operating activities, before changes in operating assets and liabilities and cash from discontinued operations, was $965.0 million for the year ended December 31, 2003, compared with $732.7 million and $735.7 million for 2002 and 2001, respectively.

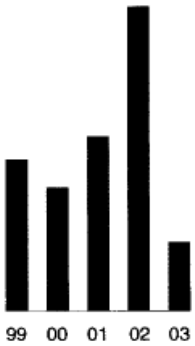
Cash from operations in 2003 reflects fluctuations due to the higher gas prices and distribution volumes of the Enbridge Gas Distribution business. Temporary differences between accounting and taxable income, driven by changes in gas costs to be settled with ratepayers, have increased the amount of future income taxes in 2003. The significant variance in operating assets and liabilities is due to an increase in accounts receivable and gas in storage resulting from higher gas costs pending recovery from ratepayers, as well as higher equal billing plan balances.

In 2002, cash from operations before changes in operating assets and liabilities was consistent with the prior year. Earnings from continuing operations were lower but include higher non-cash charges, which increased cash from operations. The non-cash charges include the writedown on the sale of the Midcoast assets and higher future income tax expense. The decreased funding requirements for operating assets and liabilities in 2002 was due to lower gas in 2002.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2004.

Capital Expenditures, Investments and Acquisitions

(millions of dollars)



99	1,141.2
00	935.7
01	1,324.2
02	2,301.9
03	520.1

Investing Activities

Cash provided from investing activities for the year ended December 31, 2003 was $259.5 million compared with cash used in investing activities of $251.7 million in 2002 and $1,621.7 million in 2001. Investing activities in 2003 represented a source of cash primarily as a result of the proceeds received on the sale of assets to EIF. Both 2003 and 2002 reflect the repayment by EEP of short-term loans required to finance acquisitions with additional amounts received in 2003 as a majority of these loans have now been repaid.

Additions to property, plant and equipment primarily related to the gas distribution utility and are consistent with prior years. Other capital additions include the construction of the Hardisty caverns and the core maintenance on the other systems. In 2002 and 2001, capital additions were higher as a result of the Terrace expansion, new facilities on the Athabasca System, and those related to Enbridge Midcoast Energy while owned by the Company.

Other investing activity in 2003 was limited to the acquisition of the Cushing-to-Chicago Pipeline and additional investments in the Alliance and Vector pipelines net of cash acquired.

Other investing in 2002 and 2001 was significantly higher as a result of some significant transactions. During 2002, the Company completed the acquisition of the Northeast Texas assets, included in the asset sale to EEP; acquired a 25% equity investment in CLH; and increased its equity ownership of Alliance. These items represent the majority of cash used for investing purposes and more than offset the cash inflows from the sale of the Enbridge Midcoast Energy assets and Energy Services business.

Financing Activities

Over the three-year period, the Company's financing requirements have reflected its growth and investment strategies. 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.

Financing activity in 2003 includes the payment of dividends and a net reduction in debt through utilization of the cash proceeds from the sale of assets to EIF. Dividends have remained consistent with the prior year with the exception of those on the common shares, which reflects a higher number of common shares as well as an increase in the dividend rate consistent with the companies' earnings growth.

In 2002, cash used for financing activities to reduce short-term debt was partially offset by cash received from the issue of additional common shares and preferred securities. These activities were consistent with the goal of improving the Company's debt-to-equity ratio and financing the growth in the business. Proceeds from the issuance of shares by EEM were used to invest in i-units of EEP, as described above.

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	4,693.1	450.0	968.6	589.3	2,685.2
Non-recourse long-term debt	725.4	32.5	84.4	72.0	536.5
Non-recourse capital leases	61.2	1.7	3.6	3.6	52.3

RISK MANAGEMENT

Operating Risk

As Enbridge continues to diversify its energy transportation and distribution businesses in North America and internationally, the risk profile of the Company will change. Entry into non-regulated businesses imposes greater economic exposure and requires more "at risk" capital. The Company's expectation of higher returns from these businesses justifies the level of risk. In addition, these operating risks are actively managed through insurance and other programs.

Market Risk

Earnings and cash flows are subject to volatility stemming from movements in interest rates, certain commodity prices, and the Canadian dollar exchange rate relative to other currencies. The Company has adopted an earnings-at-risk methodology to measure its exposure to market risk. To manage market risk, Enbridge uses derivative financial instruments to create offsetting positions to specific exposures. The Company has established risk management policies, approved by the Board of Directors, covering the use of derivative financial instruments for hedging purposes. Ongoing monitoring and senior management reporting procedures are in place. Derivative financial instruments are not used to create speculative positions. The financial instruments used and outstanding are described in Note 15 to the consolidated financial statements.

Foreign Exchange Risk

The Company has a hedging program to eliminate 80% to 100% of the long-term exposure related to its foreign currency denominated cash flows. The Company also hedges certain of its foreign currency denominated net equity investments. The redemption of the investment in OCENSA also is hedged.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on variable rate debt and floating to fixed swaps are used to manage this exposure. The Company monitors its levels of fixed and variable rate debt instruments and, from time to time, fixed to floating swaps are used to help maintain balances of each commensurate with the Company's financing strategies. The Company also 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 over-the-counter natural gas price swaps and options to manage physical exposures that arise from the merchant capacity commitments on the Alliance and Vector pipelines. The Company also uses these derivative instruments to manage any exposures that may arise from physical asset optimization and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable Liquid Products L.P., 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 gas and NGLs are fixed with swaps, or capped, or collared with options.

For the period that the Enbridge Midcoast Energy assets were owned, the Company was exposed to the margin between the price of natural gas and natural gas liquids. Enbridge used over-the-counter commodity derivatives to fix the selling price of the natural gas liquids and the cost of purchasing natural gas to establish the margins. The derivative financial instruments used to manage this exposure were transferred to EEP as part of the sale transaction.

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.

Derivative Financial Instruments Used for Risk Management

(millions of dollars unless otherwise noted) **December 31,**	**2003**			**2002**		
	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	**535.8**	**(30.6)**	**2005-2022**	535.8	24.9	2005-2022
Euro cross currency swaps	**434.7**	**(46.1)**	**2004-2019**	371.1	(54.4)	2003
Forwards *(cumulative exchange amounts)*	**1,889.5**	**67.9**	**2004-2022**	1,993.0	(244.6)	2003-2022
Energy commodities						
Natural gas *(bcf)*	**63.6**	**12.4**	**2004-2008**	35.3	(1.5)	2003-2004
Natural gas supply management *(bcf)*	**13.1**	**(3.4)**	**2004**	5.9	(0.2)	2003
Interest rates						
Interest rate swaps	**561.0**	**1.9**	**2005-2029**	934.1	0.6	2003-2029
Forward interest rate swaps	**532.0**	**(1.0)**	**2004-2005**	–	–	–

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset 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 $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

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.

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.

The carrying amounts of all financial instruments, except for debt, approximate fair value. The fair value of debt does not include the effects of hedging.

Total Debt

(millions of dollars) December 31,	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**881.4**	**990.6**	981.3	1,084.5
Gas Distribution and Services	**1,674.5**	**1,972.1**	1,749.0	1,989.2
Corporate	**3,362.1**	**3,540.1**	3,962.3	4,081.3
	5,918.0	**6,502.8**	6,692.6	7,155.0

Non-recourse debt of the joint ventures has a carrying value of $786.6 million and fair value of $845.7 million.

QUARTERLY FINANCIAL INFORMATION[1]

(millions of Canadian dollars, except for per share amounts) 2003	First	Second	Third	Fourth	Total
Operating revenue from continuing operations	**1,045.8**	**1,887.1**	**1,068.1**	**854.3**	**4,855.3**
Operating income from continuing operations	**157.2**	**449.3**	**182.7**	**102.2**	**891.4**
Margin	**0.150**	**0.238**	**0.171**	**0.120**	**0.184**
Earnings applicable to common shareholders					
Continuing operations	**103.8**	**445.4**	**90.7**	**27.3**	**667.2**
Discontinued operations	**–**	**–**	**–**	**–**	**–**
	103.8	**445.4**	**90.7**	**27.3**	**667.2**
Earnings per common share					
Continuing operations	**0.63**	**2.70**	**0.54**	**0.16**	**4.03**
Discontinued operations	**–**	**–**	**–**	**–**	**–**
	0.63	**2.70**	**0.54**	**0.16**	**4.03**
Dividends per common share	**0.415**	**0.415**	**0.415**	**0.415**	**1.660**

(millions of Canadian dollars, except for per share amounts) 2002	First	Second	Third	Fourth	Total
Operating revenue from continuing operations	1,073.2	1,645.8	1,171.0	657.5	4,547.5
Operating income from continuing operations	152.9	336.4	30.8	88.7	608.8
Margin	0.138	0.203	0.026	0.135	0.132
Earnings applicable to common shareholders					
Continuing operations	105.0	199.1	(3.9)	34.0	334.2
Discontinued operations	8.1	234.2	–	–	242.3
	113.1	433.3	(3.9)	34.0	576.5
Earnings per common share					
Continuing operations	0.66	1.26	(0.03)	0.20	2.09
Discontinued operations	0.05	1.48	–	(0.02)	1.51
	0.71	2.74	(0.03)	0.18	3.60
Dividends per common share	0.38	0.38	0.38	0.38	1.52

1 Quarterly Financial Information has been prepared in accordance with Canadian Generally Accepted Accounting Principles.

Operating revenue from continuing operations fluctuates primarily due to the seasonality of the Company's gas distribution business. This business has a September 30 year end, which results in consolidation by the Company on a quarter lag basis. Therefore, peak revenues are recorded in the Company's second quarter, which represents Enbridge Gas Distribution's winter months. The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second and fourth quarters of 2003, as well as the third quarter of 2002. Significant items which impacted 2003 and 2002 quarterly earnings are as follows:

- First quarter earnings in 2003 include a $7.1 million regulatory disallowance in the Company's gas distribution business.
- First quarter earnings in 2002 include a $17.8 million after-tax gain on a sale of marketable securities and a $6.1 million dilution gain on an EEP unit issuance.
- Second quarter earnings in 2003 include a $169.1 million after-tax gain on the sale of assets to the Enbridge Income Fund in June 2003 and a $9.2 million dilution gain on an EEP unit issuance.
- Second quarter earnings in 2002 include a $240.0 million after-tax gain on the sale of the Company's Energy Services business in May 2002.
- Third quarter earnings in 2002 include a $76.3 million after-tax writedown of the Enbridge Midcoast Energy assets, which were subsequently sold to Enbridge Energy Partnership.
- Fourth quarter earnings in 2003 include a $11.1 million dilution gain on an EEP unit issuance, and a $6.0 million dilution gain related to Noverco. Offsetting the gain is a $26.0 million write-down of a regulatory receivable and a $4.6 million regulatory decision on outsourcing, both in the Company's gas distribution business.
- Fourth quarter earnings in 2002 include a further $5.9 million after-tax writedown of the Enbridge Midcoast Energy assets from that recorded in the fourth quarter of 2002.

FOURTH QUARTER 2003 HIGHLIGHTS

Fourth quarter earnings of $27.3 million in 2003 were $6.7 million lower than earnings for the fourth quarter of 2002. Earnings growth was noted in the quarter from additional facilities put into service at the Enbridge and Athabasca Systems in early 2003, and from equity earnings from Enbridge Income Fund. In addition, the fourth quarter of 2003 also included a dilution gain from EEP of $11.1 million. These additional sources of earnings were more than offset by additional corporate expenses relating to business development, an expense for stock-based compensation, and other corporate costs primarily relating to prior year business dispositions and final settlements. Fourth quarter earnings were further reduced as a result of a $26.0 million writedown of a regulatory receivable, and a $4.6 million affiliate outsourcing disallowance in the Gas Distribution and Services segment.

SUPPLEMENTARY INFORMATION

Outstanding Share Data	Number of units outstanding
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares — issued and outstanding (voting equity shares)	171,963,027
Total issued and outstanding stock options	4,685,762

Outstanding share data information is provided as at January 23, 2004.

Related Party Transactions

Neither EEP nor EIF have employees and accordingly they use the services of the Company for managing and operating their businesses. These services, which are charged at cost in accordance with service agreements, amount to $128.9 million (2002 – $97.2 million; 2001 – $56.2 million) for EEP and $4.7 million for EIF, which began operation on June 30, 2003.

Vector Pipeline uses the services of Enbridge, a 60% interest owner, to operationally manage its business. These services, which are charged at cost in accordance with service agreements, amounted to $3.3 million for 2003 (2002 – $4.1 million; 2001 – $3.4 million).

EGD acquires its customer care services from CustomerWorks Limited Partnership under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services, which amounted to $95.5 million in 2003 (2002 – $71.8 million).

EGD has contracted for gas transportation services from Alliance Pipeline Limited Partnership and Vector Pipeline Limited Partnership. EGD is charged market prices for these services, which amounted to $40.7 million in 2003 (2002 – $41.3 million; 2001 – $34.8 million) for Alliance Pipeline, and $23.2 million in 2003 (2002 – $25.2 million; 2001 – $20.7 million) for Vector Pipeline.

A subsidiary of the company earns rental revenue from CustomerWorks Limited Partnership for the use of an automated billing system. In 2003, this revenue amounted to $25.5 million (2002 – $35.1 million). CustomerWorks Limited Partnership began operations on January 1, 2002.

In 2003, Enbridge Gas Services Inc. purchased $33.6 million (2002 – $6.3 million; 2001 – nil) of gas from Enbridge Marketing (US) Inc.

The Company also provides consulting and other services to affiliates. 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 trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

Additional information relating to Enbridge is available on www.sedar.com.

Dated February 24, 2004

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 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 and (No. 33-77022) on Form F-3 of Enbridge Inc. (the "Corporation") of our report dated January 23, 2004, relating to the financial statements of the Corporation as at December 31, 2002 and 2003 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
January 23, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 6-K

Report of Foreign Issuer
Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934

Dated April 23, 2004
Commission file number 0-21080

Enbridge Inc.

(Exact name of Registrant as specified in its charter)

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

3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrant's telephone number, including area code)

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

Form 20-F o Form 40-F þ

[Indicate by check mark whether the Registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.]

Yes o No þ

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-13456, 333-97305 AND 333-6436) AND FORM F-3 (FILE NO. 33-77022) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Press Release dated April 23, 2004.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: April 23, 2004

By: /s/ “Blaine G. Melnyk”

Blaine G. Melnyk
Corporate Secretary &
Associate General Counsel

NEWS RELEASE

Enbridge Gas Distribution Receives Decision on Late Payment Penalties

Calgary, Alberta, April 23, 2004 — Enbridge Gas Distribution Inc., a wholly owned subsidiary of Enbridge Inc., announced today that the Supreme Court of Canada has released its decision in the Garland case regarding late payment penalties. The Supreme Court of Canada has determined that Enbridge Gas Distribution will be required to repay a portion of amounts paid to it as late payment penalties from April 1994. The Supreme Court has directed that a lower court determine the amounts payable.

Late payment penalty revenues are included in the Company's estimate of revenues for the year and therefore offset rates charged to customers. Enbridge does not profit from revenues from late payment penalties, which accrue to the benefit of all customers, thereby reducing the cost of providing distribution services. These estimates and resulting rates were approved by the Ontario Energy Board ("OEB") each year. For this reason, Enbridge Gas Distribution intends to apply to the OEB in 2005 for recovery of any amounts that result from the Garland action and there is not expected to be any financial impact on the Company.

Mr. Gordon Garland, a customer of Enbridge Gas Distribution (formerly The Consumers' Gas Company Ltd.), commenced an action in 1994, asserting that Enbridge Gas Distribution's late payment penalties were contrary to Canadian federal law and seeking certification of the action as a class action. In December 2001, the Ontario Court of Appeal dismissed Mr. Garland's action. In October 2002 the Supreme Court of Canada granted leave to hear Mr. Garland's appeal, and the appeal was heard by the Supreme Court in October 2003.

Late payment penalties were voluntarily adopted in the late 1970s following review by a task force of Ontario public utilities in consultation with the then Minister of Energy and were seen as a means of providing a balanced measure of protection, not only for the individual customer, but also the broad public interest. They were designed to ensure that prompt paying customers were not disadvantaged by customers who do not pay promptly.

On February 1, 2002, Enbridge Gas Distribution changed its late payment penalty from a one-time five per cent charge to a one-time two per cent charge on current gas charges. These charges were made pursuant to rate orders issued by the Ontario Energy Board.

A copy of the full Supreme Court of Canada decision can be found at www.scc-csc.gc.ca.

When used in this news release, 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.

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