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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

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

For the fiscal year ended December 31, 2002 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:

x Annual Information Form x 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:

169,845,306 Common shares (as at December 31, 2002)

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 x 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.

x Yes o No

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Disclosure controls and procedures are defined by the Securities and Exchange Commission as those controls and procedures that are designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures within 90 days prior to filing of this Annual Report on Form 40-F and have determined that such disclosure controls and procedures are effective.

Subsequent to our evaluation, there were no significant changes in internal controls or other factors that could significantly affect internal controls, including any corrective actions with regards to significant deficiencies and material weaknesses.

The design of any system of controls and procedures is based in part upon certain assumptions about the likelihood of future events. There can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions, regardless of how remote.

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, 2002, dated March 4, 2003, 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 registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

SIGNATURES

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

ENBRIDGE INC.

Date: March 28, 2003

By: /s/ “Blaine G. Melnyk”

Blaine G. Melnyk
Corporate Secretary & Associate General Counsel

CERTIFICATIONS

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

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in the annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (and persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 28, 2003

/s/ Patrick D. Daniel

Patrick D. Daniel
President & Chief Executive Officer

CERTIFICATIONS

I, Derek P. Truswell, Chief Financial Officer, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in the annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (and persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 28, 2003

/s/ Derek P. Truswell

Derek P. Truswell
Group Vice President & Chief Financial Officer

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EXHIBIT INDEX

1. Annual Information Form of the Registrant dated March 4, 2003.

2. Audited financial statements of the Registrant and notes thereto for the fiscal years ended December 31, 2001 and 2002 and Auditor's Report thereon.

3. Management's Discussion and Analysis of the Registrant for the year ended December 31, 2002.

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



ENBRIDGE INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2002

dated
March 4, 2003

ENBRIDGE INC.

ANNUAL INFORMATION FORM
For the Year Ended December 31, 2002

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

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

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 four operating segments: Energy Transportation North, Energy Transportation South, Energy Distribution and International.

- Energy Transportation North includes the operation of a common carrier pipeline and feeder pipelines which transport crude oil and other liquid hydrocarbons, equity investments in natural gas transmission pipelines and an equity investment in a company engaged in natural gas gathering and processing.

- Energy Transportation South consists of the Company's equity investment in Enbridge Energy Partners, L.P. (EEP) and Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership). 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 owned 100% of Enbridge Midcoast Energy, which is now a wholly-owned subsidiary of EEP. The business activities of Energy Transportation South are carried out in the United States.

- The Energy Distribution business consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. This business also includes natural gas distribution activities in Quebec, New Brunswick and New York State, as well as gas services operations, including the equity investment in Aux Sable.

- 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.

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. The acquisition of the South Texas System also includes an option to purchase a 500-mile Federal Energy Regulatory Commission (FERC)-regulated natural gas transmission pipeline system that interconnects with the gathering system. In March 2002, Enbridge Midcoast Energy acquired natural gas gathering and processing facilities in northeast Texas (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. On October 17, 2002, the Company closed the sale of the United States assets of Enbridge Midcoast Energy, including the South Texas System, the option to purchase the FERC-regulated 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 i-units have been 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%. 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 their 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, 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 a recently completed 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.

In 2002, Enbridge purchased a 9.6% interest in the Alliance Pipeline from The Williams Companies Inc. (Williams) and a 6.1% interest from El Paso Corporation (El Paso) at a total cost of about $315 million. The acquisition from El Paso also includes a 9.5% interest in the Aux Sable gas processing facility. Enbridge has not assumed either company’s direct merchant capacity commitments on Alliance. The acquisitions bring Enbridge’s ownership to approximately 37.1% of the Alliance Pipeline and 30.9% of Aux Sable. The Company will acquire a further 1.1% interest in the Alliance Pipeline from El Paso in 2003. The Alliance Pipeline commenced operations in late 2000 and delivers approximately 1.3 billion cubic feet (bcf) per day of western Canadian natural gas to the U.S. Midwest states.

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 90 million Euros ($149.1 million) will become payable over the next four years if certain minimum annual volume targets are met.

In 2002, the Company commenced development of underground cavern facilities to provide crude oil storage services through a partnership with CCS Income Trust. The storage facilities are located near the Company’s main pipeline terminal at Hardisty, Alberta and capacity is expected to be approximately three million barrels. The storage facilities are expected to be in service by the end of 2003.

The facilities owned by Enbridge Pipelines (Athabasca) Inc. (Athabasca System) transport synthetic and heavy oils from northern Alberta to the main pipeline system at Hardisty, Alberta. During 2002, the MacKay River and Christina Lake lateral feeder lines were placed in service.

Phase II of the Terrace Expansion Project (Terrace) on the Enbridge System was completed in 2002 and provided an additional 40,000 barrels per day of capacity at a cost of approximately $100 million. In June 2001, Enbridge received approval from shippers to proceed with the application for Phase III of Terrace. The National Energy Board (NEB) approved the facilities application for construction of Phase III in April 2002. This final phase of Terrace is expected to be in service in 2003 and will increase capacity by 140,000 barrels per day.

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.

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.

During 2001, Enbridge and B.C. Gas Inc. created a limited partnership to develop and operate a new company, 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 BC 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.

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.

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.

The Company holds a 45% interest in the Vector Pipeline Partnership and provides operating services for the pipeline. The Vector Pipeline is a natural gas transmission pipeline between Chicago, Illinois and Dawn, Ontario and has a delivery capacity of one bcf per day. The pipeline commenced operations in late 2000.

During 2000, Enbridge increased its ownership in the Oleoducto Central S. A. (Ocensa) crude oil pipeline to 24.7% with the purchase of an additional 7.2% interest. The acquisition also included the purchase of the remaining 50% interest in CIT Colombiana S.A. (CITCol), the company that operates Ocensa through the provision of technical and managerial services.

In 2000, Enbridge entered a strategic alliance with Global Thermoelectric Inc. (Global) to develop and distribute natural gas-fuelled fuel cell products for the supply of electric power and heat for residential use. The Issuer invested $25 million in Global preferred shares to fund further technology, design and product development work required to reach a commercial launch. This investment will provide the Issuer with exclusive distribution rights in Canada for the residential units.

ITEM 4

NARRATIVE DESCRIPTION OF THE BUSINESS

Revenues by Segment

(Canadian dollars in millions)	**2002**	2001	2000
Energy Transportation North	**742.7**	695.6	699.5
Energy Transportation South	**1,264.2**	708.8	30.1
Energy Distribution	**2,506.6**	2,638.3	1,812.4
International	**27.2**	30.8	22.2
Corporate	**6.8**	7.4	6.4
Revenues from continuing operations	**4,547.5**	4,080.9	2,570.6
Revenues from discontinued operations	**181.9**	463.0	388.5
Total Revenues	**4,729.4**	4,543.9	2,959.1

ENERGY TRANSPORTATION NORTH

Energy Transportation North includes the operation of a common carrier pipeline and feeder pipelines which transport crude oil and other liquid hydrocarbons, equity investments in natural gas transmission pipelines and an equity investment in a company engaged in natural gas gathering and processing.

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 Energy Transportation South. 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 through a connecting third party pipeline. 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 a feeder pipeline system through its wholly-owned subsidiary, Enbridge Pipelines (Saskatchewan) Inc. (Saskatchewan System).

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 NEB. Total deliveries averaged 1,786,000 barrels per day in 2002.

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 party to a negotiated settlement and throughput agreement with its main shipper. Total deliveries averaged 28,100 barrels per day in 2002.

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 339 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 MacKay River and Christina Lake lateral feeder lines and tankage facilities. Enbridge Athabasca has entered into a 30-year transportation arrangement with Suncor Energy Inc., the initial shipper on the pipeline. Additional shippers in 2002 included Petro-Canada and EnCana. The Athabasca System is regulated by the Alberta Energy and Utilities Board (the AEUB).

The Saskatchewan System consists of approximately 200 miles of trunk line and 1,117 miles of pipeline on three separate gathering systems. Two of the gathering systems are located in southeastern Saskatchewan and one in southwestern Manitoba. Total deliveries averaged 164,800 barrels per day in 2002. The provinces of Saskatchewan and Manitoba regulate the gathering systems and the NEB regulates the trunk line on a complaint basis.

Enbridge System

Properties

The Enbridge System (including Terrace Phase II) consists of approximately 4,900 miles of pipe with diameters ranging from 12 inches to 48 inches, 33 main line pump station locations with a total of approximately 830,000 installed horsepower and 102 tanks with an aggregate capacity of approximately 13.8 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 with a current capacity of 1,765,000 barrels/day:

- four pipelines from Edmonton, Alberta to the US border near Gretna, Manitoba:
  - a 20-inch line;
  - a second 20-inch line with 16-inch and 18-inch loops;
  - a 24/34-inch line (24-inch with 34-inch loops to Hardisty, Alberta and 34-inch from Hardisty to Gretna); and
  - a 34/36/48-inch line (34-inch line from Edmonton to Hardisty and a 36/48-inch line from Hardisty to Gretna); and
- a fifth pipeline
  - a 24-inch line from Hardisty to Gretna.

(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, that consists of a 30-inch line with a capacity of 240,000 barrels per day.

The 2002 estimated annual capacities noted above take into account 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 or public authorities. The pumping stations, terminals and certain other facilities are located on land owned by Enbridge Pipelines.

Terrace Expansion Project

The Terrace Expansion Project, which is being undertaken by the Issuer and the Partnership, is a phased expansion that is expected to ultimately provide 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. The first phase 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.

The third phase of Terrace (Phase III) will include 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 will provide up to 140,000 barrels per day of incremental capacity at a budgeted cost of $135 million on the Enbridge System and US$208 million on the Lakehead System. The shippers have also requested that EEP proceed with the Griffith Lateral project from Mokena, Illinois to Griffith, Indiana. This will allow for better access to the Chicago market and provide operational flexibility on the Lakehead System, which makes the Enbridge System more attractive to shippers.

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 industry 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 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. The negotiated toll settlement contains incentives to increase operating efficiency. In general terms, the Incentive Tolling Agreement 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, 2002, are set forth below.

	Canadian Toll Per Barrel (Cdn dollars)
Regina, Saskatchewan	$ 0.787
U.S. border near Gretna, Manitoba	$ 1.055
Sarnia, Ontario	$ 1.193

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 tables 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, 2003 to reflect provisions in the revised Incentive Tolling Agreement, the SEP II Risk Sharing Agreement and the Terrace Agreement.

Sources of Shipments

Shipments tendered to the Enbridge System originate in oilfields and oilsands in Alberta, Saskatchewan, Manitoba, British Columbia and the Northwest Territories, and reach the Enbridge System through the NW, Athabasca, and Saskatchewan 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 Enbridge 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 the Buffalo, New York area.

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, 2002.

(thousands of barrels per day)	Deliveries 2002	2001	2000
Prairie Provinces			
Light crude oil	**170**	158	127
Medium and heavy crude oil	**73**	76	70
Refined products	**81**	76	81
	324	310	278
United States			
Light crude oil	**286**	273	295
Medium and heavy crude oil	**601**	631	595
Natural gas liquids	**6**	5	25
	893	909	915
Ontario & Quebec			
Light crude oil	**380**	391	383
Medium and heavy crude oil	**78**	78	86
Natural gas liquids	**111**	104	103
	569	573	572
	1,786	1,792	1,765
Barrel Miles (billions)	**351**	350	383
Average Haul (miles)	**539**	535	594

Enbridge System average deliveries include Line 9 volumes of 204,000 barrels per day (2001 – 217,000; 2000 – 208,000).

In 2002, total Enbridge deliveries, including feeder pipelines and the Lakehead System, were 2,088,000 barrels per day (2001 – 2,109,000; 2000 — 2,072,000).

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 safety and environmental management systems (SMS and EMS) and has established policies, programs and practices for conducting safe and environmentally sound operations. The SMS and EMS 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 regulations and acts, 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. In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. The Company is assessing and evaluating the federal government's approach to implementation. Until these plans become certain, the Company will not be able to quantify the impact, if any, on its operations. The Company is encouraged by recent producer reactions, particularly their commitment to oil sands development, which support the Company's outlook for the sustainability of supply for the 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.

To measure safety and environmental performance, 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 2002, in-line inspections for corrosion and pipe deformities such as dents and cracks 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 880 individuals in its Energy Transportation North operations.

NATURAL GAS BUSINESS

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 37.1% interest in the Alliance Pipeline and will acquire a further 1.1% interest in 2003.

The Issuer holds a 45% 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 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.

The Issuer also holds an approximate 40% 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.

ENERGY TRANSPORTATION SOUTH

Energy Transportation South includes the Company's 14.1% equity investment in the Partnership and other wholly or partially owned feeder liquids pipelines. 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. The business activities of Energy Transportation South are carried out in the United States.

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 during 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. From May 2001 to October 2002, Enbridge owned 100% of Enbridge Midcoast Energy.

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.

The Frontier System is owned by Frontier Pipeline Company, a Wyoming general partnership owned 78% 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 65,000 barrels per day and total deliveries averaged 44,300 barrels per day in 2002 (2001 – 40,123 barrels per day). The Frontier System is regulated by the 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 47,500 barrels per day in 2002 (2001 – 25,500 barrels per day). 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 400,000 barrels per day. The pipeline transports crude oil from the Patoka pipeline hub to the Chicago, Illinois area. Total deliveries averaged approximately 189,500 barrels per day in 2002 (2001 – 204,100 barrels per day). 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 64,200 barrels per day in 2002 (2001 – 68,900 barrels per day). The Toledo System is regulated by the FERC.

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, 2002 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 Exchange Commission and through www.edgar.com. No part of either Form 10-K is intended to be incorporated by reference in this Annual Information Form of Enbridge Inc.

ENERGY DISTRIBUTION

The Energy Distribution business includes the gas distribution operations of Enbridge Gas, Enbridge Commercial Services, which owns the Company's investment in CustomerWorks, the Company's investment in Noverco Inc. (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, and its equity investment in Aux Sable.

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 almost 1.6 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 natural gas distribution services provided to its customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis (i.e., a non-contract basis). The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm service contract, 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 with respect to natural 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 buy/sell or a transportation service arrangement. Under the buy/sell arrangement, a customer purchases gas directly from a western Canadian producer or marketer and sells it to Enbridge Gas either at a TransCanada PipeLines Limited (TransCanada) receipt point in western Canada or at a TransCanada delivery point in Ontario. Enbridge Gas, in turn, resells the gas, now integrated into its general supply portfolio, back to the customer at its end-use location. 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 Enbridge Gas redelivers an equivalent amount of gas to the customer's 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 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, Enbridge Gas maintains a diversified gas supply portfolio. During 2002, Enbridge Gas acquired approximately 117 bcf of natural gas of which 41.2% was purchased under long-term contracts with independent western Canadian producers. The remaining 58.8% was purchased from Ontario producers and from other sources through short-term or monthly spot purchases. Enbridge Gas also transported 279 bcf of natural gas on behalf of direct purchase customers operating under the 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 a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecasted system gas supply.

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.

The transportation 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 gas purchased directly by end-use customers.

TransCanada's transportation tolls, which are approved by the NEB, consist of a fixed cost (the demand component) and a variable cost (the 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 2002. In 2003, Enbridge Gas 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 beginning in fiscal year 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 MichCon as well as access to U.S. gas supplies through 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 Pipeline Company (ANR) and Michigan Consolidated Gas Company (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 Pipeline. In the winter, gas is withdrawn from storage and delivered to Dawn and, from there, transported to Enbridge Gas' major market area of Toronto through the transmission facilities of Union. Enbridge Gas has transportation contracts with TransCanada, Vector Pipeline and Union for the delivery of gas to and from storage.

Properties

At the end of its 2002 fiscal year, Enbridge Gas owned and operated approximately 19,010 miles of mains (2001 – 18,169 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; these 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 2003 and rate decisions for 2002 and 2001 are summarized as follows.

	2003	2002		2001	
	Requested	Approved	Requested	Approved	Requested
Rate base (Cdn $millions)	**3,226**	3,019	3,114	3,118	2,977
Rate of return on rate base	**8.32%**	8.26%	9.32%	8.54%	8.68%
Deemed common equity component of total capital structure	**35.00%**	35.00%	35.00%	35.00%	35.00%
Rate of return on common equity	**9.69%**	9.66%	11.38%	9.54%	9.73%

2003 Fiscal Year

In September 2002, Enbridge Gas filed its fiscal 2003 rate application with the OEB, requesting an order to approve rates for the sale, distribution, transmission and storage of gas, which reflected a gross revenue deficiency, or proposed increase in revenue rates, of $134.5 million. In November 2002, Enbridge Gas' rate application was updated for changes in rate base, an increase in distribution volume and impacts of the October 1, 2002 quarterly rate adjustment, resulting in a revised revenue deficiency of $101.7 million. Of this amount, approximately $9.0 million is associated with changes to the distribution volume forecast, gas in storage inventory valuation and cost of capital (including the application of OEB-approved rate of return on common equity formula), offset somewhat by a decline in federal taxation rates. A further $43.8 million of the increase arises from a requested increase in operating and maintenance

expense recovery, and $13.0 million from the proposed mechanism for recovery of a $50.0 million regulatory receivable. The remainder relates to variances in all other items requested for recovery within Enbridge Gas' cost of service application. The 2003 rate application is a traditional cost-of-service application as Enbridge Gas' performance-based regulation plan ended in 2002. It is expected that the 2003 rate application will be heard by the OEB in early 2003 and a decision is anticipated by mid 2003.

In December 2002, the Company applied for and received OEB approval to effect an annualized $88.3 million increase in gas commodity costs, due to higher natural gas commodity prices. New rates, reflecting the increase in the natural gas commodity costs, were effective January 1, 2003.

The 2003 rate application includes a request to review and revise the current formula used to calculate the rate of return on common equity. This request will be heard in a separate phase of the 2003 rate hearing and, as such, the increase to a proposed rate of return of 11.50% versus the 9.69% produced by the current formula has not been incorporated in the calculation of the $101.7 million deficiency. The increase in the requested rate of return reflects 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. Enbridge Gas does not mark up the cost of the gas commodity; increases or decreases are due to fluctuations in the market price of natural gas. In September 2002, Enbridge Gas applied for and received approval to effect an annualized $36.8 million decrease in gas commodity costs, due to declining natural gas prices. Rates reflecting this decrease were effective October 1, 2002.

In September 2001, Enbridge Gas filed its fiscal 2002 rate application with the OEB, requesting an order to approve rates for the sale, distribution, transmission and storage of gas, which reflected a gross revenue deficiency of $81.3 million. In January 2002, Enbridge Gas' rate application was updated for current economic factors, changes in rate base, a decrease in distribution volume and impacts of the first quarterly rate adjustment, resulting in a revised revenue deficiency of $49.2 million. The deficiency is comprised of load balancing costs and distribution costs. The distribution costs are being driven by growth in operations and maintenance expense from the application of the PBR formula, increased rate base and an increase in the rate of return on common equity. The increase in the requested rate of return subsequently was withdrawn by Enbridge Gas for the purpose of establishing rates for 2002.

Final rates, reflecting a revenue deficiency of $9.2 million, were implemented effective August 1, 2002. The decrease in revenue deficiency from the January 2002 update was mainly due to the withdrawal of the request for a higher rate of return and the outcome of the negotiated settlement.

The OEB approved the 2002 revenue requirement and final rates in August 2002. In December 2002, the OEB released its decision with respect to other matters in the 2002 application. In that decision, the OEB stated it was not satisfied that the decisions to enter into long-term transportation contracts with Alliance Pipeline were prudent and directed Enbridge Gas to increase a regulatory liability account by $11.0 million. The OEB also directed that further information be supplied on system gas cost allocations and affiliate outsourcing arrangements as part of the 2003 rates hearing. Enbridge Gas filed a notice of motion, requesting the OEB to review its decision on Alliance Pipeline and affiliate outsourcing or, in the alternative in the latter matter, a generic hearing on rules for affiliate outsourcing. This notice of motion has been dismissed by the OEB. Enbridge Gas has also filed an appeal to the Divisional Courts on matters arising from what Enbridge Gas believes to be errors in law in the decision.

In December 2001, Enbridge Gas applied for and received OEB approval to effect an annualized $136.5 million decrease in gas commodity costs, due to declining natural gas commodity prices. Rates, reflecting this decrease in natural gas commodity costs, were effective January 1, 2002.

In February 2002, Enbridge Gas applied for and received OEB approval to effect an annualized $131.7 million decrease in gas commodity costs and new rates went into effect April 1, 2002. New rates were

implemented on July 1, 2002 following OEB approval to effect an annualized $290.0 million increase in gas commodity costs.

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, in January 2003, an appeal was filed with the Divisional Court of Appeal. 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.

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, which 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 2002, approximately 56% 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. In 2002, natural gas enjoyed, on average, a price advantage on an equivalent annual volume basis of about 50% against electricity and 17% 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. In 2003, natural gas enjoys, on average, a price advantage on an equivalent annual volume basis of about 43% against electricity and 20% against domestic fuel oil. 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. In the commercial market sector, where natural gas competes against light fuel oil, the price advantage is neutral. However, the commercial users' ability to fuel switch requires a long-term decision and a capital investment. In parts of the industrial market sector, where natural gas competes with heavy fuel oil, the periodic pricing of heavy fuel oil on a spot basis to stimulate customer demand creates increased risk of customers temporarily switching to heavy fuel oil.

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.

Enbridge Gas remains committed to investing in collaborative research, development, demonstration and implementation of new technologies, which improve the efficiency of utilizing natural gas. Improved end-use offerings not only provide customers with a choice of more efficient, cleaner-burning natural gas appliances, but also deliver improved space conditioning, water heating, commercial cooking and industrial process equipment across a broad range of consumer segments.

Enbridge Gas is facilitating the emergence of Distributed Energy, which is the simultaneous production of electricity and heat from natural gas turbines and reciprocating engines. Customer interest in private gas-fired power production derives from expected increases in the cost of electricity, as well as reliability and power quality concerns. As such, many customers look to Enbridge Gas for technical and sales assistance to help them decide if and how they might benefit from private power generation efficiencies.

Historical Operating Statistics for Enbridge Gas

Year ended September 30,	**2002**	2001	2000
Gas supply and sendout (mmcf) [1]			
Natural gas purchased	**117,376**	186,873	202,857
Gas into storage	**(51,508)**	(113,598)	(117,556)
Gas out of storage	**63,033**	112,320	108,021
Total gas sendout	**128,901**	185,595	193,322
Gas sales to customers (mmcf) [1]			
Residential	**74,132**	99,595	100,790
Commercial	**42,531**	63,323	65,486
Industrial	**8,352**	18,056	15,711
Wholesale	**3,523**	1,387	4,413
Total sales	**128,538**	182,361	186,400
Used by Enbridge Gas (mmcf) [1]	**226**	311	275
Other (mmcf) [1]	**137**	2,923	6,647
	128,901	185,595	193,322
Transportation of gas (mmcf) [1]	**281,416**	243,125	234,826
Total sales and transportation of gas (mmcf) [1]	**409,954**	425,486	421,225
Degree day deficiency [2]			
Actual	**3,362**	3,743	3,526
Forecast based on normal weather	**3,700**	3,816	3,929
Number of active customers – year end [3]	**1,597,579**	1,546,255	1,497,359
Average use per residential customer (mcf) [1]	**97**	130	107
Number of employees – year end	**1,585**	1,563	1,769
Miles of mains in use – year end	**19,010**	18,173	17,799

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 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., which 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, 2002, Enbridge Gas had 1,585 employees, 43.9% of whom are unionized and the majority is represented by the Communications, Energy and Paperworkers Union, Local 975. The current negotiated collective agreement expired on December 31, 2002. Management of Enbridge Gas is working with the union to reach a new agreement.

(Readers are also directed to the Renewal Annual Information Form of Enbridge Gas for the year ended September 30, 2002, which is not incorporated by reference, a copy of which has been filed with Canadian Securities Regulatory Authorities.)

OTHER ENERGY DISTRIBUTION BUSINESSES

Other gas distribution operations include Enbridge Gas Services, Gazifère Inc., Niagara Gas Transmission Ltd. (Niagara Gas), a 32% interest in Noverco, a 63% interest in Enbridge Gas New Brunswick and a 30.9% interest in Aux Sable. 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 and provides information technology, fleet services, call management centre, customer care and billing services to Enbridge Gas and others. In 2001, Enbridge entered into a limited partnership with BC Gas Inc. to operate 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 3.5 million customers including customers of BC Gas Utility and Enbridge's gas distribution business. 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 1,600 customers. Over 200 kilometres (124 miles) of distribution main has been installed with the capability of attaching approximately 7,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

The Issuer holds a 30.9% 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.

Other energy distribution businesses employed approximately 325 employees on December 31, 2002.

INTERNATIONAL

The Issuer's international business operates and invests in energy transportation and related energy projects outside of Canada and the United States. It also provides consulting and training services related to proprietary pipeline operation 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 entity operating 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.

The Jose Terminal is operated under a long-term agreement in which the Issuer has a 45% interest in the operating fees. The 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, with current throughput capacity of approximately 800,000 barrels per day.

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.

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

CORPORATE

Corporate activities are limited to business development and corporate financing. 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.

The Issuer performs liquids marketing activities through a joint venture interest in Tidal Energy Marketing Inc., maintains an investment in Global Thermoelectric 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.

The Issuer's corporate activities and operations employ approximately 150 individuals.

ITEM 5

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Selected Consolidated Financial Information

(millions of Canadian dollars)	**2002**	2001	2000
Total Revenues	**4,729.4**	4,543.9	2,959.1
Earnings Applicable to Common Shareholders			
Continuing Operations	**334.2**	413.2	357.7
Discontinued Operations	**242.3**	45.3	34.6
	576.5	458.5	392.3
Long-Term Debt (excluding current maturities)	**6,040.3**	5,913.3	5,572.3
Preferred Securities	**533.7**	339.7	340.4
Preference Shares, Series A	**125.0**	125.0	125.0
Total Assets	**12,987.4**	13,127.7	10,609.4

Per Share Data

(Canadian dollars)	**2002**	2001	2000
Earnings Per Share[1]			
Continuing Operations	**2.09**	2.63	2.32
Discontinued Operations	**1.51**	0.28	0.22
	3.60	2.91	2.54
Diluted Earnings Per Share Continuing Operations	**2.06**	2.60	2.31
Discontinued Operations	**1.50**	0.28	0.22
	3.56	2.88	2.53
Dividends[2]			
Common Shares[3]	**1.520**	1.400	1.270
Preference Shares, Series A	**1.375**	1.375	1.375

Notes:

1. Earnings per share are computed using the weighted average number of common shares outstanding of 160.3 million (2001 — 157.3 million; 2000 - 154.5 million). The weighted average number of shares outstanding have been reduced by the Issuer's pro rata interest in its own common shares resulting from the investment in Noverco Inc.
2. The Issuer's outstanding Preferred Shares, Series A contain restrictions requiring that no dividends shall be declared or paid on common shares if there has been a deferral of dividends on the Preferred Shares, Series A. In addition, the Issuer's outstanding Preferred Securities contain restrictions requiring that no dividends shall be declared or paid on any of its capital stock if there has been a deferral of distributions on the Preferred Securities. At December 31, 2002, there were no restrictions preventing the Issuer from paying dividends on common shares. Quarterly dividends are determined by the Issuer's Board of Directors.
3. On January 29, 2003, the Board of Directors announced an increase in the quarterly dividend from $0.38 per common share to $0.415 per common share.

ITEM 6

MANAGEMENT'S DISCUSSION AND ANALYSIS

The information, which is found under the caption "Management's Discussion and Analysis" on pages 14 through 38 and under the caption "Selected Quarterly Financial Data" on page 70 of the Annual Report of Enbridge Inc. for the year ended December 31, 2002, is incorporated herein by reference.

ITEM 7

MARKET FOR SECURITIES

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 8

DIRECTORS AND OFFICERS

Directors

The following table sets forth the names of the Directors of Enbridge Inc. effective December 31, 2002, 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] Houston, Texas	Corporate Director; Vice Chairman of the Board of Directors of El Paso Corporation (integrated energy company) in 2001; prior thereto, Chairman, President and Chief Executive Officer of the Coastal Corporation since 1997.	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; prior thereto, Executive Vice President & Chief Operating Officer - Energy Transportation Services since 1998.	2000
E. SUSAN EVANS[3,6] Calgary, Alberta	Corporate Director	1996
WILLIAM R. FATT[3,6] 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
MICHEL GOURDEAU,[4,5] St. Lambert, Québec	President, Oil & Gas Division of Hydro-Québec (integrated power company) since 2002; prior thereto, other senior management positions with Hydro- Québec since 1997.	2002

Name [1] and Municipality of Residence	Principal Occupation for the Five Preceding Years	Year First Became a Director[2]
LOUIS D. HYNDMAN[3,4] Edmonton, Alberta	Senior Partner, Field Atkinson Perraton LLP (law firm)	1993
BRIAN F. MACNEILL[3,5] Calgary, Alberta	Chair of Petro-Canada (integrated oil and gas company) since 2000; prior thereto, Chief Executive Officer of the Company from September to December 2000; prior thereto, President & Chief Executive Officer of the Company	1991
ROBERT W. MARTIN[3,6] Toronto, Ontario	Corporate Director; Chairman of Silcorp Limited (convenience stores) from 1993 to 1999.	1992
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
DONALD J. TAYLOR[5,6] Jacksons Point, Ontario	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.

Officers

The following table sets forth the names of the executive officers, their current office with the Issuer effective December 31, 2002, 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; prior thereto, Executive Vice President & Chief Operating Officer – Energy Transportation Services since 1998.
MEL F. BELICH Group Vice President, International Calgary, Alberta	Group Vice President, International since September 2000; prior thereto, Senior Vice President, International Development & Corporate Law, and Corporate Secretary since 1999; prior thereto, Senior Vice President, General Counsel & Corporate Secretary.
J. RICHARD BIRD Group Vice President, Energy Transportation North Calgary, Alberta	Group Vice President, Energy Transportation North since May 2001; prior thereto, Group Vice President, Transportation since September 2000; prior thereto, Senior Vice President, Corporate Planning & Development since 1997.
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; prior thereto, Senior Vice President, Human Resources since 1998.
STEPHEN J.J. LETWIN Group Vice President, Distribution & Services Aurora, Ontario	Group Vice President, Distribution & Services since September 2000; prior thereto, President & Chief Operating Officer – Energy Services since 1999; prior thereto, Senior Vice President, Corporate Services and Chief Financial Officer of TransCanada PipeLines Limited since 1998; President, Petroleum Group of TransCanada Energy Management Limited from 1996 to 1999.
DEREK P. TRUSWELL Group Vice President & Chief Financial Officer Calgary, Alberta	Group Vice President & Chief Financial Officer since September 2000; prior thereto, Senior Vice President & Chief Financial Officer.
DAN C. TUTCHER Group Vice President, Energy Transportation South Houston, Texas	Group Vice President, Energy 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, Planning & Development Calgary, Alberta	Group Vice President, Planning & Development since September 2000; prior thereto, President, Enbridge Pipelines Inc.

Name, Position and Municipality of Residence	Position and Principal Occupations for the Five Preceding Years
KARYN A. BROOKS Vice President & Controller Calgary, Alberta	Vice President & Controller since April 2000; prior thereto, Vice President, Financial Services, Transmission of TransCanada PipeLines Limited since August 1999; prior thereto, Vice President & Controller of TransCanada PipeLines Limited.
SCOTT R. WILSON Vice President, Finance Calgary, Alberta	Vice President, Finance since October 2001; prior thereto, Vice President & Treasurer since 1998.
JOHN K. WHELEN Vice President & Treasurer Calgary, Alberta	Vice President & Treasurer since February, 2002; prior thereto, Assistant Treasurer.
AL MONACO Vice President, Financial Services Calgary, Alberta	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.
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.

ITEM 9

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, 2002, is contained in the Issuer's Management Information Circular dated March 4, 2003 furnished in connection with the Annual and Special Meeting of Shareholders to be held on May 7, 2003 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, 2002.

Effective Date

Unless otherwise specifically herein provided, the information contained in this Annual Information Form is stated effective as at December 31, 2002.

ENBRIDGE INC.

Consolidated Financial Statements

December 31, 2002

AUDITORS' REPORT

To the Shareholders of Enbridge Inc.

We have audited the consolidated statements of financial position of Enbridge Inc. as at December 31, 2002 and 2001 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2002. 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, 2002 and 2001 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada
January 27, 2003

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 27, 2003 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
Chartered Accountants

Calgary, Alberta, Canada
January 27, 2003

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Year ended December 31,		
	2002	2001	2000
	(millions of Canadian dollars, except per share amounts)		
Revenues			
Gas sales	2,987.7	2,675.3	1,407.0
Transportation	1,296.6	1,177.6	1,035.2
Energy services	263.2	228.0	128.4
	4,547.5	4,080.9	2,570.6
Expenses			
Gas costs	2,578.0	2,202.8	958.8
Operating and administrative	834.1	739.1	613.0
Depreciation	403.9	392.5	387.5
Loss on sale of Enbridge Midcoast Energy assets	122.7	—	—
	3,938.7	3,334.4	1,959.3
Operating Income	608.8	746.5	611.3
Investment and Other Income (Note 15)	283.1	194.9	171.5
Interest Expense (Note 8)	(422.0)	(437.1)	(389.2)
	469.9	504.3	393.6
Income Taxes (Note 13)	(102.1)	(66.7)	(13.7)
Earnings From Continuing Operations	367.8	437.6	379.9
Earnings From Discontinued Operations (Note 5)	242.3	45.3	34.6
Earnings	610.1	482.9	414.5
Preferred Security Distributions (Note 9)	(26.7)	(17.5)	(15.3)
Preferred Share Dividends (Note 10)	(6.9)	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	576.5	458.5	392.3
Earnings Applicable to Common Shareholders			
Continuing Operations	334.2	413.2	357.7
Discontinued Operations	242.3	45.3	34.6
	576.5	458.5	392.3
Earnings Per Common Share (Note 10)			
Continuing Operations	2.09	2.63	2.32
Discontinued Operations	1.51	0.28	0.22
	3.60	2.91	2.54
Diluted Earnings Per Common Share (Note 10)			
Continuing Operations	2.06	2.60	2.31
Discontinued Operations	1.50	0.28	0.22
	3.56	2.88	2.53

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31,		
	2002	**2001**	**2000**
	(millions of Canadian dollars, except per share amounts)		
Retained Earnings at Beginning of Year	812.3	581.3	503.1
Earnings Applicable to Common Shareholders	576.5	458.5	392.3
Effect of Change in Accounting for Income Taxes	—	—	(112.0)
Effect of Change in Accounting for Stock-Based Compensation	(5.4)	—	—
Preferred Securities Issue Costs	(4.2)	—	—
Common Share Dividends	(251.1)	(227.5)	(202.1)
Retained Earnings at End of Year	1,128.1	812.3	581.3
Dividends Paid Per Common Share	1.52	1.40	1.27

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2002	2001	2000
	(millions of Canadian dollars)		
Cash Provided By Operating Activities			
Earnings from continuing operations	367.8	437.6	379.9
Charges/(credits) not affecting cash			
Depreciation	403.9	392.5	387.5
Equity earnings less than/(in excess of) cash distributions	(44.6)	1.2	(52.0)
Gain on reduction of ownership interest (Note 7)	(10.0)	(23.4)	—
Loss on foreign exchange contracts	—	—	24.5
Gain on sale of securities	(21.4)	—	—
Loss on sale of Enbridge Midcoast Energy assets (Note 3)	122.7	—	—
Future income taxes	(64.7)	3.4	(117.1)
Other	(21.0)	(75.6)	(23.0)
Changes in operating assets and liabilities (Note 16)	151.6	(323.1)	(515.4)
Cash provided by operating activities of discontinued operations	26.3	1.9	179.1
	910.6	414.5	263.5
Investing Activities			
Acquisitions	(289.3)	(599.1)	(16.5)
Long-term investments	(1,282.7)	(41.8)	(554.9)
Additions to property, plant and equipment	(729.9)	(683.3)	(364.3)
Sale of Energy Services business (Note 5)	993.3	—	—
Sale of Enbridge Midcoast Energy assets (Note 3)	529.3	—	—
Sale of other assets	73.8	—	—
Sale of securities	110.5	—	—
Repayments by/(loans to) affiliate	358.1	(280.6)	—
Changes in construction payable	(14.8)	(14.0)	(5.7)
Other	—	(2.9)	(8.4)
	(251.7)	(1,621.7)	(949.8)
Financing Activities			
Net change in short-term borrowings and short-term debt	(1,180.9)	1,521.4	(105.2)
Long-term debt issues	247.4	905.6	965.4
Long-term debt repayments	(382.7)	(979.6)	(133.3)
Non-controlling interests	0.2	(4.1)	21.2
Preferred securities issued	193.5	—	—
Common shares issued	293.1	23.3	175.4
Enbridge Energy Management shares issued (Note 7)	421.9	—	—
Preferred security distributions	(26.7)	(17.5)	(15.3)
Preferred share dividends	(6.9)	(6.9)	(6.9)
Common share dividends	(251.1)	(227.5)	(202.1)
	(692.2)	1,214.7	699.2
Increase/(Decrease) in Cash	(33.3)	7.5	12.9
Cash at Beginning of Year	74.0	66.5	53.6
Cash at End of Year	40.7	74.0	66.5

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31,	
	2002	2001
	(millions of Canadian dollars)	
ASSETS		
Current Assets		
Cash	40.7	74.0
Accounts receivable and other	817.5	1,270.2
Gas in storage	583.8	665.6
Current assets of discontinued operations (Note 5)	—	123.0
Current assets held for sale (Note 3)	—	148.9
	1,442.0	2,281.7
Property, Plant and Equipment, net (Note 6)	6,947.6	6,817.5
Long-Term Investments (Note 7)	3,371.5	1,772.8
Receivable from Affiliate (Note 3)	701.5	—
Deferred Amounts	315.8	329.7
Future Income Taxes (Note 13)	209.0	142.0
Long-Term Assets of Discontinued Operations (Note 5)	—	750.0
Long-Term Assets Held for Sale (Note 3)	—	1,034.0
	12,987.4	13,127.7
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	247.5	410.9
Accounts payable and other	714.1	679.9
Interest payable	102.6	100.2
Current maturities and short-term debt (Note 8)	652.3	1,819.7
Current liabilities of discontinued operations (Note 5)	—	73.8
Current liabilities held for sale (Note 3)	—	125.3
	1,716.5	3,209.8
Long-Term Debt (Note 8)	6,040.3	5,913.3
Future Income Taxes (Note 13)	837.4	722.8
Non-Controlling Interests (Note 7)	560.8	131.1
Long-Term Liabilities of Discontinued Operations (Note 5)	—	118.6
	9,155.0	10,095.6
Shareholders' Equity		
Share capital		
Preferred securities (Note 9)	533.7	339.7
Preferred shares (Note 10)	125.0	125.0
Common shares (Note 10)	2,169.0	1,875.9
Retained earnings	1,128.1	812.3
Foreign currency translation adjustment	12.3	7.4
Reciprocal shareholding (Note 7)	(135.7)	(128.2)
	3,832.4	3,032.1
Commitments and Contingencies (Note 18)	12,987.4	13,127.7

Approved by the Board:



Donald J. Taylor
Chair



Robert W. Martin
Director

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

Enbridge Inc. (Enbridge or the Company) is a leader in the transportation and distribution of energy. Enbridge conducts its business through four operating segments: Energy Transportation North, Energy Transportation South, Energy Distribution, 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.

Energy Transportation North

Energy Transportation North includes the operation of a common carrier pipeline and feeder pipelines which transport crude oil and other liquid hydrocarbons, equity investments in natural gas transmission pipelines and an equity investment in a company engaged in natural gas gathering and processing.

Energy Transportation South

Energy Transportation South consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP) and Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership). 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 owned 100% of Enbridge Midcoast Energy which is now a wholly owned subsidiary of EEP. The business activities of Energy Transportation South are carried out in the United States.

Energy Distribution

The Energy Distribution business consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. This business also includes natural gas distribution activities in Quebec, New Brunswick and New York State, as well as gas services operations, including the equity investment in Aux Sable.

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 19. 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 those 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 Energy Distribution business is conducted primarily through a wholly-owned subsidiary, Enbridge Gas Distribution Inc. (Enbridge Gas), formerly The Consumers' Gas Company Ltd. 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.

Regulation

The Company's Energy Transportation and Energy Distribution activities 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 Energy Transportation and Energy Distribution operations 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.

Effective January 1, 2000, the Company adopted new recommendations for accounting for income taxes. Adoption of the recommendations resulted in a charge to retained earnings of $112.0 million, of which $76.1 million related to rental assets of Enbridge Gas no longer regulated by the OEB, $22.4 million related to the tax effect of differences between the carrying amounts of investments and their respective tax bases, and the remaining $13.5 million related to other non-regulated assets.

Foreign Currency Translation

The functional currency of the Company's foreign operations, except for certain financing and investing operations, is the U.S. dollar. These operations are self-sustaining and translated into Canadian dollars using the current rate method. Gains and losses resulting from these translation adjustments are included as a separate component of shareholders' equity.

The Company's foreign financing and investing operations are integrated with those of the parent company and are translated into Canadian dollars using the temporal method. Gains and losses resulting from these translation adjustments are included in earnings.

Cash

Cash includes short-term and demand deposits with a term to maturity of three months or less 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. 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 for the Energy Transportation operations are not determinable and will be recognized when approved for recovery in tolls by the regulators. Accordingly, no provision has been made for these costs as there is reasonable expectation that they will be recovered through future tolls when they become payable.

Depreciation expense for Energy Distribution 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.

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 new standard of the Canadian Institute of Chartered Accountants (CICA) related to goodwill and other intangible assets. Under the new 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 is being 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 both defined benefit and defined contribution pension plans. 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 Energy Distribution 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 Energy Distribution 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 new CICA standard for stock-based compensation. Awards not required to be expensed under the new standard, such as stock options, are accounted for as capital transactions when the options are exercised. The standard requires retroactive application for certain other stock compensation awards as a charge to opening retained earnings without restatement of prior periods. Outstanding stock appreciation rights, which expire in 2003 and 2004, resulted in a charge to opening retained earnings, on adoption, of $5.4 million.

Comparative Amounts

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

Change in Accounting Policy

In September 2002, the CICA announced the deferral of the effective date of the accounting guideline on Hedging Relationships to fiscal years beginning on or after July 1, 2003. In addition, in December 2002, the CICA approved an exposure draft to amend the guideline. As a result, the Company is deferring adoption of the new guideline.

2. SEGMENTED INFORMATION

	Year ended December 31, 2002					
	Energy Transportation					
	North	South	Energy Distribution	International	Corporate[1]	Consolidated
	(millions of dollars)					
Revenues	742.7	1,264.2	2,506.6	27.2	6.8	4,547.5
Gas costs	—	(1,051.4)	(1,526.6)	—	—	(2,578.0)
Operating and administrative	(263.6)	(130.7)	(404.3)	(19.0)	(16.5)	(834.1)
Depreciation	(143.2)	(24.8)	(229.9)	(2.9)	(3.1)	(403.9)
Loss on sale of Enbridge Midcoast Energy assets	—	(122.7)	—	—	—	(122.7)
Operating income/(loss)	335.9	(65.4)	345.8	5.3	(12.8)	608.8
Investment and other income	82.7	44.2	19.9	64.0	72.3	283.1
Interest and preferred equity charges	(99.8)	(28.1)	(161.1)	(1.6)	(165.0)	(455.6)
Income taxes	(82.6)	7.9	(90.8)	0.3	63.1	(102.1)
Earnings/(loss) from continuing operations	236.2	(41.4)	113.8	68.0	(42.4)	334.2
Earnings from discontinued operations						242.3
Earnings applicable to common shareholders						576.5

	Year ended December 31, 2001					
	Energy Transportation					
	North	South	Energy Distribution	International	Corporate[1]	Consolidated
	(millions of dollars)					
Revenues	695.6	708.8	2,638.3	30.8	7.4	4,080.9
Gas costs	—	(558.9)	(1,643.9)	—	—	(2,202.8)
Operating and administrative	(242.6)	(71.3)	(385.1)	(19.0)	(21.1)	(739.1)
Depreciation	(134.9)	(29.2)	(222.1)	(2.5)	(3.8)	(392.5)
Operating income/(loss)	318.1	49.4	387.2	9.3	(17.5)	746.5
Investment and other income/(expense)	69.6	53.0	(0.2)	27.0	45.5	194.9
Interest and preferred equity charges	(104.0)	(28.3)	(161.7)	(0.1)	(167.4)	(461.5)
Income taxes	(78.6)	(27.7)	(43.5)	(0.6)	83.7	(66.7)
Earnings/(loss) from continuing operations	205.1	46.4	181.8	35.6	(55.7)	413.2
Earnings from discontinued operations						45.3
Earnings applicable to common shareholders						458.5

	Year ended December 31, 2000					
	Energy Transportation					
	North	South	Energy Distribution	International	Corporate[1]	Consolidated
	(millions of dollars)					
Revenues	699.5	30.1	1,812.4	22.2	6.4	2,570.6
Gas costs	—	—	(958.8)	—	—	(958.8)
Operating and administrative	(243.9)	(18.5)	(307.8)	(17.8)	(25.0)	(613.0)
Depreciation	(156.3)	(7.5)	(214.3)	(0.7)	(8.7)	(387.5)
Operating income/(loss)	299.3	4.1	331.5	3.7	(27.3)	611.3
Investment and other income	55.3	35.3	50.8	22.6	7.5	171.5
Interest and preferred equity charges	(106.4)	(1.9)	(166.1)	—	(137.0)	(411.4)
Income taxes	(55.6)	(14.2)	(13.0)	0.1	69.0	(13.7)
Earnings/(loss) from continuing operations	192.6	23.3	203.2	26.4	(87.8)	357.7
Earnings from discontinued operations						34.6
Earnings applicable to common shareholders						392.3

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 was restated to reflect changes in the internal organization of the Company in the fourth quarter of 2002.

Total Assets

	December 31,	
	2002	2001
	(millions of dollars)	
Energy Transportation North	4,621.3	4,244.2
Energy Transportation South[1]	1,151.1	1,544.9
Energy Distribution	5,275.8	5,401.8
International	830.7	294.3

Corporate	1,108.5	769.5
	12,987.4	12,254.7
Discontinued Operations	—	873.0
	12,987.4	13,127.7

1. Includes goodwill of $330.4 million in 2001 related to the acquisition of Enbridge Midcoast Energy, sold in the fourth quarter of 2002, as described in Note 3.

Additions to Property, Plant and Equipment

	Year ended December 31,		
	2002	**2001**	**2000**
		(millions of dollars)	
Energy Transportation North	257.4	216.1	85.9
Energy Transportation South	128.9	85.9	0.6
Energy Distribution	313.2	302.6	255.4
International and Corporate	7.5	35.2	2.0
	707.0	639.8	343.9
Discontinued Operations	22.9	43.5	20.4
	729.9	683.3	364.3

2. SEGMENTED INFORMATION (Continued)

Geographic Information

Revenues

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Canada	3,102.3	3,317.7	2,511.1
United States	1,418.0	736.8	41.8
Other	27.2	26.4	17.7
	4,547.5	4,080.9	2,570.6

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

Property, Plant and Equipment

	December 31,	
	2002	2001
	(millions of dollars)	
Canada	6,733.6	6,630.4
United States	204.8	176.9
Other	9.2	10.2
	6,947.6	6,817.5

3. SALE OF ENBRIDGE MIDCOAST ENERGY ASSETS

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, for proceeds of US$820.0 million. The Company received cash proceeds of approximately US$339.0 million and the remaining consideration, in the form of assumed affiliate debt, will be settled when EEP secures additional financing.

The Company continues to exercise significant influence over the assets sold and, for the period that the assets were held for sale, results of operations were not segregated from continuing operations. For the year ended December 31, 2002, excluding the loss on sale of $82.2 million after tax, the assets generated after-tax earnings of $7.3 million.

4. ACQUISITIONS

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

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Net gain on disposition, net of tax	240.0	—	—
Earnings	2.3	45.3	34.6
Earnings from discontinued operations	242.3	45.3	34.6

Selected Earnings Information

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Revenues	181.9	463.0	388.5
Income tax expense/(recovery)	34.6	2.5	(15.6)
Allocated interest expense	12.1	35.4	38.5

6. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2002			
	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
		(millions of dollars)		
Energy Transportation North	3.3%	4,526.2	1,657.9	2,868.3
Energy Transportation South	4.1%	262.0	99.7	162.3
Energy Distribution	3.6%	4,687.4	822.3	3,865.1
Other	6.6%	73.0	21.1	51.9
		9,548.6	2,601.0	6,947.6

	December 31, 2001			
	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
		(millions of dollars)		
Energy Transportation North	2.5%	4,260.1	1,516.8	2,743.3
Energy Transportation South	3.9%	266.9	90.0	176.9
Energy Distribution	3.2%	4,542.2	706.7	3,835.5
Other	6.1%	74.3	12.5	61.8
		9,143.5	2,326.0	6,817.5

7. LONG-TERM INVESTMENTS

	Ownership Interest	December 31, 2002	December 31, 2001
		(millions of dollars)	
Equity Investments			
Energy Transportation North			
Alliance Pipeline	37.1%	678.6	376.6
Vector Pipeline	45.0%	474.8	472.9
AltaGas Services	40.3%	204.2	181.1
		1,357.6	1,030.6
Energy Transportation South			
The Partnership	14.1%	815.5	93.5
Chicap Pipeline	22.8%	32.4	31.7
		847.9	125.2
Energy Distribution			
Noverco	32.1%	28.9	33.9
Aux Sable	30.9%	135.0	124.6
		163.9	158.5
International			
Compañía Logistica de Hidrocarburos (CLH)	25.0%	541.2	—
Other		31.2	28.8
Cost Investments			
Energy Distribution			
Noverco		181.4	181.4
International			
OCENSA Pipeline		223.3	223.3
Global Thermoelectric		25.0	25.0
		3,371.5	1,772.8

Equity investments include $551.9 million (2001 — $208.1 million) representing the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the date of purchase. The excess 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.

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 interests 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 $529.9 million. The Company's net investment in the Partnership, after deducting the non-controlling interest of $438.8 million, is $376.7 million.

In 2002 and prior to the formation of EEM, EEP completed a public issue of partnership units. As the Company elected not to participate in this offering, its effective interest in EEP was reduced to 12.9% from 13.6%. This resulted in recognition of a dilution gain of $10.0 million, before tax. In 2001, EEP completed two public issues of partnership units, in which the Company elected not to participate. As a result of these offerings, the Company's effective ownership interest in EEP was reduced to 13.6% from 15.3%, resulting in recognition of dilution gains of $23.4 million, before tax.

In 2002, the Company invested $294.7 million in Alliance and $20.6 million in Aux Sable, increasing the Company's ownership interests from 21.4% to 37.1% and 21.4% to 30.9%, respectively. The purchase price included $7.1 million representing the excess of the 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.

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 90 million Euros ($149.1 million) will become payable over the next four years if certain minimum annual volume targets are met. The purchase price included $340.9 million representing the excess of the 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.

Noverco holds an approximate 10% reciprocal shareholding in the Company. As a result, the Company has a pro-rata interest of 3.2% in its own shares (2001 — 3.2%). Both the equity investment in Noverco Inc. and shareholders' equity have been reduced by the reciprocal shareholding of $135.7 million (2001 — $128.2 million).

Income from Equity Investments

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Energy Transportation North	78.6	65.6	54.2
Energy Transportation South	41.9	32.0	37.7
Energy Distribution	(3.7)	(17.9)	7.5
International	34.1	0.3	—
	150.9	80.0	99.4

Consolidated retained earnings at December 31, 2002 includes undistributed earnings from equity investments of $155.7 million (2001 — $104.1 million).

8. DEBT

	Weighted Average Interest Rate	Maturity	December 31, 2002	December 31, 2001
			(millions of dollars)	
Energy Transportation North				
Debentures	9.07%	2008-2024	300.0	300.0
Medium-term notes	6.66%	2005-2029	622.5	622.3
Other[1]			58.8	150.1
Energy Transportation South				
Senior term notes[2] (US$275.0 million)	8.08%	2005-2007	397.8	397.8
Variable rate credit facility[3]		2003	252.7	477.8
Energy Distribution				
Debentures	11.00%	2004-2024	635.0	635.0
Medium-term notes[4]	5.86%	2003-2028	1,105.0	1,105.0
Other			9.0	9.5
Corporate				
Medium-term notes	6.14%	2004-2032	1,788.7	1,927.9
Variable rate credit facility		2005	400.0	400.0
Preferred securities (Note 9)	7.79%	2048-2051	16.3	10.3
Other[5]			1,106.8	1,697.3
Total Debt			6,692.6	7,733.0
Current maturities of long-term debt			225.0	325.0
Other short-term debt			427.3	1,494.7
Current Maturities and Short-Term Debt			652.3	1,819.7
Long-Term Debt			6,040.3	5,913.3

1. Primarily commercial paper borrowings.
2. The principal amount is recorded at the swapped rate.
3. Includes US$160.0 million (2001 — US$300.0 million).
4. Includes $100.0 million floating rate note swapped to 3.03%.
5. Primarily commercial paper borrowings. Includes US$582.5 million (2001 — US$470.2 million).

Short-term debt in the amount of $1,000.0 million (2000 — $840.0 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, 2003 through 2007 are $225.0 million, $450.0 million, $928.6 million, $440.0 million and $369.3 million, respectively.

Short-term Borrowings

Short-term borrowings, which primarily finance gas in storage and other working capital items, are comprised of commercial paper with maturities of less than one year. Of these borrowings, $100 million (2001 — $200.0 million) was swapped to a weighted average fixed interest rate of 2.6% (2001 — 5.7%).

Interest Rate Management

	Weighted Average Effective Rate[1]	December 31, 2002 Notional Amounts	2001 Notional Amounts
		(millions of dollars)	
Energy Transportation North			
Commercial paper	6.04%	25.4	25.4
Energy Transportation South			
Senior term notes[2]	7.40%	US$275.0	US$275.0
Variable rate credit facilities	—	—	US$140.0
Corporate			
Medium-term notes	—	—	40.0
Variable rate debt	2.30%	400.0	400.0
Commercial paper	—	—	150.0

1. Reflects the effective rate after giving effect to floating to fixed swap agreements.

2. Subject to a cross-currency swap.

Interest Expense

	Year ended December 31, 2002	2001	2000
		(millions of dollars)	
Long-term debt	392.9	345.0	375.2
Commercial paper and other short-term debt	29.0	85.8	1.5
Short-term borrowings	9.6	12.2	18.5
Capitalized	(9.5)	(5.9)	(6.0)
	422.0	437.1	389.2

In 2002, total interest paid was $429.3 million (2001 — $452.2 million; 2000 — $372.0 million).

Credit Facilities

	December 31, 2002 Committed	Uncommitted	Drawdowns
		(millions of dollars)	
Energy Transportation North	150.0	—	—
Energy Transportation South (US$300.0 million)	473.9	—	252.7
Energy Distribution	659.0	5.5	14.5
Corporate	1,900.0	—	400.0
	3,182.9	5.5	667.2

Committed facilities carry a weighted average standby fee of 0.097% per annum on the unutilized portion. The committed facilities for Energy Transportation North, Energy Transportation South and Energy Distribution expire in 2003 and are extendible annually subject to the approval of the lenders. The committed facilities for Corporate expire in 2003, 2005 and 2007 and are extendible annually thereafter subject to the approval of the lenders. Drawdowns under all of these facilities bear interest at prevailing market rates.

9. PREFERRED SECURITIES

In 2002, the Company completed a public offering of 7.8% Preferred Securities for $200.0 million. Net proceeds were $193.5 million. The Company also has outstanding $175.0 million of 7.6% and $175.0 million of 8.0% Preferred Securities. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after the fifth anniversary of each issue. The Company has the right to defer, subject to certain conditions, payments of distributions on the securities for up to 20 consecutive quarterly periods. Since deferred and regular distributions may be settled through the issuance of common shares at the Company's option, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $533.7 million at December 31, 2002 (2001 — $339.7 million).

10. 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

	December 31,					
	2002		2001		2000	
	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
	(millions of dollars; number of common shares in millions)					
Balance at beginning of year	162.9	1,875.9	161.8	1,852.6	156.3	1,677.2
Dividend Reinvestment and Share Purchase Plan	0.2	8.3	0.2	7.2	0.2	7.2
Issued to Noverco	0.5	23.1	—	—	0.6	19.7
Public issue	5.0	225.4	—	—	4.5	143.9
Other	1.1	36.3	0.9	16.1	0.2	4.6
Balance at end of year	169.7	2,169.0	162.9	1,875.9	161.8	1,852.6

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. On or after 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.

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 (2001 — 5.2 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 exercise of stock options.

	December 31,		
	2002	2001	2000
	(number of common shares in millions)		
Weighted average shares outstanding	160.3	157.3	154.5
Effect of dilutive securities			
Stock options	1.7	1.5	0.8
Diluted weighted average shares outstanding	162.0	158.8	155.3

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.

11. STOCK OPTION PLAN

The Company's Incentive Stock Option Plan (1999) includes fixed stock options and performance-based stock options. A maximum of 12 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 September 16, 2012.

Outstanding Options

	December 31,					
	2002		2001		2000	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
	(options in thousands; exercise price in dollars)					
Options at beginning of year	5,120	29.06	4,112	26.76	3,116	26.63
Options granted	1,024	43.80	2,024	30.11	1,360	26.74
Options exercised	(1,003)	26.31	(843)	19.27	(179)	19.85
Options cancelled or expired	(99)	37.59	(173)	34.47	(185)	31.17
Options at end of year	5,042	32.16	5,120	29.06	4,112	26.76
Options vested	2,639		2,853		1,757	

Option Characteristics

	December 31, 2002				
	Options Outstanding			Options Vested	
Exercise Price Range	Number (000's)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number (000's)	Weighted Average Exercise Price
	(options in thousands; exercise price in dollars)				
12.44 - 19.99	532	1.84	16.74	532	16.74
20.00 - 29.99	1,445	6.29	25.81	867	25.21
30.00 - 39.99	2,027	6.95	35.61	1,229	34.47
40.00 - 47.71	1,038	9.09	42.14	11	40.10
	5,042			2,639	

Performance-based Options

The Plan provides for the grant of performance-based options to executive officers. Vesting is based on the performance of the Company's common share price. New performance-based options were granted in 2002. The options vest in equal annual installments over a five-year period and become exercisable, as to 50% of the grant, when the market price of a common share exceeds $61.00 per share for 20 consecutive trading days during the five-year period ended September 16, 2007. If the share price exceeds $71.00 for 20 consecutive trading days prior to September 16, 2007, the remaining options will become exercisable. The performance-based options expire on September 16, 2007 if the share price target is not reached but extend to September 16, 2010 for options that become exercisable.

	December 31,					
	2002		2001		2000	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
	(options in thousands; exercise price in dollars)					
Options at beginning of year	1,479	32.03	1,480	31.60	1,480	31.60
Options granted	810	46.30	65	41.13	—	—
Options exercised	(244)	31.66	—	—	—	—
Options cancelled	—	—	(66)	31.35	—	—
Options at end of year	2,045	37.73	1,479	32.03	1,480	31.60
Options vested	1,235	32.10	740	31.31	—	—

Pro forma Compensation Expense

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

	Year ended December 31, 2002
	(millions of dollars)
Earnings applicable to common shareholders from continuing operations	
As reported	334.2
Stock-based compensation expense	2.9
Pro forma	331.3
Earnings applicable to common shareholders	
As reported	576.5
Stock-based compensation expense	2.9
Pro forma	573.6
Earnings per common share from continuing operations	
As reported	2.09
Pro forma	2.07
Earnings per common share	
As reported	3.60
Pro forma	3.58

1. Pro forma earnings and earnings per share do not reflect options granted prior to January 1, 2002, the date of adoption of the standard on stock-based compensation.

2. The Black-Scholes model was used to calculate the fair value of the fixed stock options. Significant assumptions include a risk-free interest rate of 5.33%, expected volatility of 25%, an expected life of 10 years and an expected dividend yield of 3.51%. The weighted average grant-date fair value was $11.42 for the fixed stock options granted during the year ended December 31, 2002.

3. A barrier valuation model was used to calculate the fair value of the performance-based options. Significant assumptions include a risk-free interest rate of 4.20%, expected volatility of 24%, an expected life of 8 years and an expected dividend yield of 3.46%. The weighted average grant-date fair value was $7.65 for performance-based options granted during the year ended December 31, 2002.

12. 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 US 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 US 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 million, to manage the balance of fixed and floating rate debt.

Energy Commodity Costs

As a result of the sale of the assets of Enbridge Midcoast Energy, the Company's commodity price risk exposure arising from holding inventory and purchase and sale commitments has been reduced. The Company continues to use 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.

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, 2002, the Company had entered into natural gas price swaps and options to manage the price for approximately 4.3%, or 5.9 billion cubic feet, of its forecast fiscal 2003 system gas supply.

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,					
	2002			2001		
	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
	(millions of dollars except natural gas derivatives)					
Foreign exchange						
U.S. cross currency swaps	535.8	24.9	2005-2022	535.8	26.3	2005-2022
Euro cross currency swaps	371.1	(54.4)	2003	—	—	—
Forwards (cumulative exchange amounts)	1,993.0	(244.6)	2003-2022	2,130.1	(165.9)	2002-2022
Energy Commodities						
Natural gas (bcf)	35.3	(1.5)	2003-2004	74.4	(41.1)	2002-2006
Natural gas supply management (bcf)	5.9	(0.2)	2003	36.0	(37.1)	2002
Interest rates						
Interest rate swaps	934.1	0.6	2003-2029	955.4	(12.7)	2002-2029
Forward interest rate swaps	—	—	—	600.0	(6.5)	2002

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $449 million, to exchange Canadian for U.S. dollars. The instruments expire in 2003, 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 receivable of $36.9 million as at December 31, 2002 (2001 — $23.9 million).

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, 2002 and 2001. A credit risk on derivative financial instruments amounted to $105.3 million at December 31, 2002 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

	December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(millions of dollars)			
Energy Transportation North	981.3	1,084.5	1,072.4	1,116.8
Energy Transportation South	650.5	686.6	875.6	910.6
Energy Distribution	1,749.0	1,989.2	1,749.5	1,956.6
Corporate	3,311.8	3,394.7	4,035.5	4,055.6
	6,692.6	7,155.0	7,733.0	8,039.6

Trade Credit Risk

Trade receivables related to Energy Transportation North 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 Energy Distribution 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 $31.1 million at December 31, 2002 (2001 — $29.9 million).

13. INCOME TAXES

Income Tax Rate Reconciliation

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Earnings before income taxes	746.9	552.1	412.6
Combined statutory income tax rate	38.0%	41.0%	43.3%
Income taxes at statutory rate	283.8	226.3	178.8
Increase/(decrease) resulting from:			
Tax rate reductions on future income tax balances	8.1	(67.5)	(103.7)
Future income taxes related to regulated operations	(36.7)	(35.7)	(40.9)
Non-taxable items, net	(99.5)	(28.2)	(31.0)
Lower foreign tax rates	(42.2)	(36.8)	(21.0)
Large Corporations Tax in excess of surtax	16.9	18.8	16.1
Other	6.3	(7.7)	(0.2)
Income Taxes	136.7	69.2	(1.9)
Continuing operations	102.1	66.7	13.7
Discontinued operations	34.6	2.5	(15.6)
	136.7	69.2	(1.9)
Effective income tax rate	18.3%	12.5%	—

In 2002, income taxes paid amounted to $105.2 million (2001 — $110.5 million; 2000 — $114.7 million).

Components of Future Income Taxes

	December 31,	
	2002	2001
	(millions of dollars)	
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	313.8	403.5
Differences in accounting and tax bases of investments	525.7	267.6
Other	110.1	154.5
	949.6	825.6
Future Income Tax Assets		
Loss carryforwards	283.0	232.1
Other	38.2	12.7
	321.2	244.8
Total Net Future Income Tax Liability	628.4	580.8

Accumulated future income taxes related to rate-regulated operations which have not been recorded in the accounts amounted to $511.2 million at December 31, 2002 (2001 — $506.3 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, 2002, the Company has recognized the benefit of unused tax loss carryforwards of $822.4 million. Unused tax loss carryforwards expire as follows: 2003 — $1.6 million; 2004 — $5.8 million; 2005 — $33.8 million; 2006 - - $129.1 million; 2007 — $182.3 million; 2008 — $69.2 million and 2009 and beyond — $400.6 million.

Geographic Components of Pretax Earnings and Income Taxes

	Year ended December 31,		
	2002	2001	2000
	(millions of dollars)		
Earnings before income taxes			
Canada	346.1	297.2	273.3
United States	(5.0)	103.8	73.3
Other	128.8	103.3	47.0
Continuing operations	469.9	504.3	393.6
Discontinued operations	276.9	47.8	19.0
	746.8	552.1	412.6
Current income taxes			
Canada	154.8	44.4	129.4
United States	3.2	8.9	(4.5)
Other	8.8	10.0	5.9
Continuing operations	166.8	63.3	130.8
Discontinued operations	36.9	20.1	24.4
	203.7	83.4	155.2
Future income taxes			
Canada	(54.5)	(9.0)	(112.4)
United States	(10.5)	12.4	(4.7)
Other	0.3	—	—
Continuing operations	(64.7)	3.4	(117.1)
Discontinued operations	(2.3)	(17.6)	(39.9)
	(67.0)	(14.2)	(157.0)
Continuing operations	102.1	66.7	13.7
Discontinued operations	34.6	2.5	(15.6)
	136.7	69.2	(1.9)

14. 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 Energy Transportation North pension plan provides non-contributory defined pension and/or defined contribution benefits to employees. The Energy Transportation South pension plan provides either non-contributory defined benefit pension benefits or contributory defined contribution pension benefits. The Enbridge Gas pension plan provides contributory defined benefit pension and/or defined contribution benefits to the majority of its employees.

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 most recent actuarial valuation was performed as of January 1, 2002.

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 Energy Transportation South pension plan, contributions to the defined contribution plans are also based on employee contributions. For defined contribution pension benefits, pension expense equals amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions

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

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

	2002	2001	2002	2001
	OPEB		Pension Benefit	
	(millions of dollars)			
Change in benefit obligation				
Benefit obligation, January 1	132.3	113.5	742.7	651.2
Service cost	4.2	3.7	18.7	20.4
Interest cost	8.8	8.0	45.9	45.4
Amendments	—	2.8	0.7	22.1
Employee contributions	0.3	0.3	0.1	4.1
Actuarial loss	31.4	6.4	8.5	38.2
Benefits paid	(5.7)	(4.7)	(37.9)	(44.0)
Divestitures	(10.6)	—	(67.8)	—
Effect of exchange rate changes	(0.2)	2.3	(0.8)	5.3
Benefit obligation, December 31	160.5	132.3	710.1	742.7
Fair value of plan assets				
Fair value of plan assets, January 1	29.6	23.8	1,076.7	1,218.8
Actual return on plan assets	3.0	2.3	(20.3)	(122.9)
Employer's contributions	8.5	6.4	19.7	9.4
Employee contributions	0.3	0.3	0.1	4.1
Benefits paid	(5.7)	(4.7)	(37.9)	(44.0)
Other	—	—	(2.3)	—
Divestitures	—	—	(100.9)	—
Effect of exchange rate changes	(0.2)	1.5	(2.0)	11.3
Fair value of plan assets, December 31	35.5	29.6	933.1	1,076.7
Asset/(Liability)				
Plan assets in excess/(deficiency) of projected benefit obligations	(125.0)	(102.7)	223.0	334.0
Unrecognized prior service cost	3.4	3.6	20.8	25.6
Unrecognized plan surplus	36.2	46.3	—	—
Unrecognized net loss/(gain)	31.5	2.8	4.8	(119.7)
Recorded asset/(liability)	(53.9)	(50.0)	248.6	239.9

Net Pension Plan and OPEB Costs

	Year ended December 31,		
	2002	2001	2000
		(millions of dollars)	
Benefits earned during the year	25.2	26.3	23.0
Interest cost on projected benefit obligations	54.5	55.2	51.1
Expected return on plan assets	(75.3)	(93.7)	(76.2)
Amortization and deferral of unrecognized amounts	6.9	(6.8)	(8.9)
Amount credited to EEP	(1.7)	5.5	6.5
Pension and OPEB expense/(credit)	9.6	(13.5)	(4.5)

The above tables reflect the funded status, recorded pension and OPEB assets and liabilities and pension and OPEB expense 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 Enbridge Gas, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Enbridge Gas plans and the accrual method for other plans, the Company's pension expense was $3.6 million (2001 — $4.0 million credit; 2000 — $2.7 million expense). The pension asset was $73.1 million (2001 — $64.8 million). The Company's OPEB expense totalled $6.8 million (2001 — $5.9 million; 2000 — $5.6 million). The OPEB liability was $8.4 million (2001 — $6.8 million). The pension and OPEB assets and obligations for discontinued operations were included in the sale transaction.

Economic Assumptions

The assumptions made in the measurement of pension expense and the projected benefit obligation or asset of the pension plans and OPEB are as follows.

	Year ended December 31,					
	2002	2001	2000	2002	2001	2000
	OPEB			Pension Benefits		
Discount rate	6.75 - 7.25%	7.0 - 7.5%	7.0 - 7.5%	6.75 - 7.25%	6.75 - 7.5%	7.0 - 7.5%
Average rate of salary increases				4.0%	4.0%	4.0%
Average rate of return on pension plan assets				3.9 - 8.0%	7.75 - 8.0%	7.75 - 8.0%
Medical cost trend rate	4.5 - 14.0%	4.5 - 11.0%	4.5 - 6.8%			
Dental cost trend rate	4.5 - 5.5%	4.5 - 6.0%	4.5 - 6.0%			

A 1% change in the assumed medical and dental care trend rate would result in a change of $27.1 million in the accumulated post-employment benefit obligations and a change of $2.2 million in OPEB expense.

15. INVESTMENT AND OTHER INCOME

	Year ended December 31,		
	2002	2001	2000
	(millions of dollars)		
Equity investments	150.9	80.0	99.4
Cost investments	61.1	51.9	44.4
Investment income	22.9	16.3	14.7
Allowance for equity funds used during construction	5.3	3.9	2.7
Gain/(loss) on foreign currency contracts	0.1	(1.7)	(24.5)
Gain on reduction of EEP ownership interest	10.0	23.4	—
Gain on sale of marketable securities	21.4	—	—
Other	11.4	21.1	34.8
	283.1	194.9	171.5

16. CHANGES IN OPERATING ASSETS AND LIABILITIES

	Year ended December 31,		
	2002	2001	2000
	(millions of dollars)		
Accounts receivable and other	75.0	(583.7)	(65.3)
Gas in storage	76.0	(145.8)	(144.7)
Deferred amounts	72.4	(77.6)	(195.8)
Accounts payable and other	(76.4)	493.1	(132.8)
Interest payable	4.6	(9.1)	23.2
	151.6	(323.1)	(515.4)

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

17. RELATED PARTY TRANSACTIONS

EEP does not have any employees and uses the services of the Company for managing and operating its business. These services, which are charged at cost in accordance with service agreements, amounted to $97.2 million (2001 — $56.2 million; 2000 — $46.7 million).

18. COMMITMENTS AND CONTINGENCIES

Enbridge Gas

The remediation of discontinued manufactured gas plant sites may result in future costs. The probable overall cost of remediation cannot be determined at this time due to uncertainty about the existence or extent of environmental risks, the complexity of laws and regulations, particularly with respect to sites decommissioned years ago and no longer owned by Enbridge Gas, and the selection of alternative remediation approaches. Although there are no known regulatory precedents in Canada, there are precedents in the United States for recovery in rates of costs of a similar nature. If Enbridge Gas must contribute to any remediation costs, it would be generally allowed to recover in rates those costs not recovered through insurance or by other means and believes that the ultimate outcome of these matters would not have a significant impact on its financial position.

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 will hear the plaintiff's appeal of the Ontario Court of Appeal's decision, released in December 2001, to dismiss a Notice of Appeal filed by the plaintiff in April 2000. The Company believes it has sound defences to the plaintiff's claim and it intends to vigorously defend the action.

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 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$279 million at December 31, 2002.

19. 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

	Year ended December 31,		
	2002	2001	2000
	(millions of dollars except per share amounts)		
Earnings under Canadian GAAP	610.1	482.9	414.5
Preferred security distributions[1]	(26.7)	(17.5)	(15.3)
Stock-based compensation[2]	(12.1)	(15.2)	—
Tax effect of the above adjustment	4.9	6.1	—
Future income tax recovery/(expense)[3]	—	92.8	(182.8)
Earnings under U.S. GAAP	576.2	549.1	216.4
Unrealized net gain/(loss) on cash flow hedges[5]	19.5	(150.8)	—
Foreign currency translation adjustment[5]	(1.3)	15.1	16.2
Comprehensive income	594.4	413.4	232.6
Earnings per common share	3.55	3.45	1.36
Diluted earnings per common share	3.51	3.41	1.35

Financial Position

	December 31,			
	2002		2001	
	Canada	United States	Canada	United States
	(millions of dollars)			
Cash[4]	40.7	42.7	74.0	71.3
Accounts receivable and other[4]	817.5	843.4	1,270.2	1,313.5
Property, plant and equipment[4]	9,548.6	9,506.6	9,143.5	9,116.0
Accumulated depreciation[4]	2,601.0	2,596.3	2,326.0	2,323.1
Long-term investments[4]	3,371.5	3,421.0	1,772.8	1,801.6
Deferred amounts[3, 4]	315.8	1,178.7	329.7	1,342.8
Short-term borrowings	247.5	256.8	410.9	410.9
Accounts payable and other[4]	714.1	921.1	679.9	923.4
Current maturities and short-term debt	652.3	658.5	1,819.7	1,819.7
Long-term debt[1]	6,040.3	6,612.5	5,913.3	6,293.2
Future income taxes[3, 5]	628.4	1,403.0	580.8	1,499.7
Preferred securities[1]	533.7	—	339.7	—
Retained earnings	1,128.1	1,098.9	812.3	781.2
Additional paid in capital[2]	—	12.1	—	15.2
Accumulated other comprehensive income/(loss)[5]	12.3	(103.2)	7.4	(121.4)

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 $565.0 million at December 31, 2002 (2001 — $345.5 million).

2. Stock-based Compensation

   The Company accounts for stock-based compensation for U.S. GAAP purposes in accordance with APB 25, *Accounting for Stock Issued to Employees,* which requires the use of the intrinsic value-based method to measure compensation expense. Under Canadian GAAP, the Company's performance-based options do not give rise to compensation expense. Under U.S. GAAP, the performance-based options which vested during 2002 gave rise to pre-tax compensation expense of $12.1 million (2001 — $6.9 million; 2000 — nil).

   Starting in 2002, the Company accounts for SARs in accordance with the new Canadian accounting standard for stock-based compensation which results in the same compensation expense as under U.S. GAAP. Under U.S. GAAP in 2001 and 2000, the Company's stock appreciation rights (SARs) are accounted for using the intrinsic value method which resulted in pre-tax compensation expense of $8.3 million and nil, respectively.

3. Future Income Taxes

   Canadian GAAP requires that the effect of tax rate reductions are 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. In 2000, future income taxes of $76.5 million, related to the unbundling transaction and charged to retained earnings under Canadian GAAP as part of the adoption of the new income tax standard, are charged to earnings as a write-down of the regulatory asset 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 $549.3 million (2001 — $574.4 million) and the incremental revenue required for the recovery of unrecorded taxes of $316.0 million (2001 — $370.5 million).

4. Accounting for Joint Ventures

Under U.S. GAAP, the Company's investments in joint ventures are accounted for using the equity method.

5. Accumulated Other Comprehensive Income

At December 31, 2002, accumulated other comprehensive income consists of an accumulated foreign currency translation adjustment of $28.1 million (2001 — $29.4 million) and net unrealized losses of $131.3 million (2001 — $150.8 million) for derivative financial instruments.

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.

	Year ended December 31,		
	2002	2001	2000
	(millions of dollars except per share amounts)		
Earnings under U.S. GAAP			
As reported	576.2	549.1	216.4
Stock-based compensation expense	7.3	4.6	2.6
Pro forma	568.9	544.5	213.8
Earnings per common share			
As reported	3.55	3.45	1.36
Stock-based compensation expense	0.05	0.03	0.02
Pro forma	3.50	3.42	1.34
Diluted earnings per common share			
As reported	3.51	3.41	1.35
Stock-based compensation expense	0.04	0.03	0.02
Pro forma	3.47	3.38	1.33

The fair value of stock options was calculated in the same manner, using the same assumptions, as disclosed in Note 11 except that for Canadian GAAP, only awards granted since the adoption of the new CICA standard for stock-based compensation on January 1, 2002 are included. Assumptions used for U.S. GAAP comparative periods are as follows.

	Year ended December 31,	
	2001	2000
Risk free interest rate	5.38%	5.41%
Expected life (years)	10	10
Expected volatility	25%	25%
Expected quarterly dividends	$ 0.38	$ 0.35

The weighted average grant-date fair value of options granted during 2001 under the fixed option plan in 2001 and 2000 was $10.09 and $7.80, respectively.

New Accounting Standards

Accounting for Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which is to be adopted for fiscal years beginning after June 15, 2002. This standard requires that legal obligations associated with the retirement of long-lived tangible assets be recognized at fair value when incurred. The Company will adopt the new standard effective January 1, 2003. Since the majority of the Company's operations are rate-regulated, the new standard is not expected to have a material impact on earnings. A similar standard has been issued by the Canadian Institute of Chartered Accountants effective January 1, 2004.

Accounting for Costs Associated with Exit or Disposal Activities

In June 2002, the FASB issued SFAS No. 146 , *Accounting for Costs Associated with Exit or Disposal Activities,* which is effective for exit or disposal activities initiated on or after December 31, 2002. This standard replaces Emerging Issues Task Force Issue 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity". The standard requires liabilities associated with exit or disposal activities to be recorded, at fair value, as they are incurred rather than on the adoption of a formal plan of disposal.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities, which is to be adopted for interim periods commencing after July 15, 2003. The Company is assessing the impact of this standard, if any, on its financial statements.

Exhibit 3

Management's Discussion and Analysis

CONSOLIDATED RESULTS

FINANCIAL HIGHLIGHTS

	2002	2001	2000
	(millions of Canadian dollars, except per share amounts)		
Earnings Applicable to Common Shareholders			
Energy Transportation North	236.2	205.1	192.6
Energy Transportation South	(41.4)	46.4	23.3
Energy Distribution	113.8	181.8	203.2
International	68.0	35.6	26.4
Corporate	(42.4)	(55.7)	(87.8)
Earnings from continuing operations	334.2	413.2	357.7
Discontinued operations	242.3	45.3	34.6
	576.5	458.5	392.3
Earnings Per Share			
Earnings — Continuing operations	2.09	2.63	2.32
Earnings — Discontinued operations	1.51	0.28	0.22
	3.60	2.91	2.54
Dividends Per Share	1.52	1.40	1.27
Common Share Dividends	251.1	227.5	202.1

Earnings applicable to common shareholders (earnings) for the year ended December 31, 2002 were $576.5 million, or $3.60 per common share, compared with $458.5 million, or $2.91 per common share, in 2001. Liquids pipelines and international operations contributed to the growth in earnings, along with higher equity earnings from Enbridge Energy Partners, L.P. (EEP). These increases were offset in part by lower earnings from Enbridge Gas Distribution (Enbridge Gas) due to warmer weather in 2002 than in 2001. Earnings for 2002 also included an after-tax gain of $240.0 million from the sale of the Energy Services business and an after-tax loss of $82.2 million on assets sold to EEP, included in Energy Transportation South. Prior year's earnings included the benefit of $58.5 million related to income tax rate reductions.

As shown below, after adjusting for significant one-time gains or losses and the impact of weather, earnings for the year ended December 31, 2002 were $428.4 million, compared with $387.8 million for 2001.

	2002	2001	2000
	(millions of Canadian dollars, except per share amounts)		
Earnings applicable to common shareholders	576.5	458.5	392.3
Gain on sale of Energy Services business	(240.0)	—	—
Loss on sale of Enbridge Midcoast Energy assets	82.2	—	—
Gain on sale of securities	(17.8)	—	—
Weather	29.3	(5.0)	22.1
Dilution gains	(6.1)	(15.2)	—
Tax rate reductions	(1.4)	(58.5)	(94.9)
Other	5.7	8.0	15.6
Adjusted earnings	428.4	387.8	335.1
Adjusted earnings per share	$ 2.67	$ 2.47	$ 2.17
Adjusted diluted earnings per share	$ 2.64	$ 2.44	$ 2.16

Enbridge had several significant achievements during the year.

- The acquisition of a 25% interest in Compañia Logistica de Hidrocarburos CLH, S.A. (CLH) was completed in the first quarter. CLH is Spain's largest refined products transportation and storage business.

- In May, Enbridge sold its Energy Services business for cash proceeds of $1 billion.

- The Company closed the sale of the United States assets of Enbridge Midcoast Energy to EEP for consideration of US$820 million. Concurrent with the sale, Enbridge Energy Management, L.L.C. (EEM) completed an initial public offering of shares, the proceeds of which were used to purchase i-units in EEP. The Company's interests in EEP and EEM collectively are referred to as the Partnership.

- In the fourth quarter, the Company increased its ownership interest in Alliance to 37.1% through the purchase of a 9.6% interest from The Williams Companies Inc. (Williams) and a 6.1% interest from El Paso Corporation (El Paso). Enbridge will acquire an additional 1.1% interest in Alliance from El Paso at the end of the first quarter of 2003. As part of the El Paso transaction, Enbridge's interest in the Aux Sable natural gas processing facility increased to approximately 30.9%.

Earnings from continuing operations for the year ended December 31, 2002 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 the Partnership 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.

For the year ended December 31, 2001, earnings from continuing operations were $413.2 million, or $2.63 per share, compared with $357.7 million, or $2.32 per share, in 2000. The higher earnings reflect improved operating results from Enbridge Gas and the Enbridge System. The acquisition of Midcoast Energy Resources, Inc. also contributed to higher earnings. In addition, the Company realized dilution gains from the issuance of units by EEP and improved results from corporate activities. These

increases were partially offset by higher financing costs, a reduced contribution from Vector, a higher loss from Aux Sable, and income tax rate reductions that had a smaller positive impact on earnings in 2001 than 2000.

Dividends paid on common shares increased in each of the last three years from growth in the dividend per share and a higher number of outstanding common shares. The quarterly dividend per share increased to $0.38 in the first quarter of 2002 from $0.35 per share established in the first quarter of 2001. In the second quarter of 2000 the quarterly dividend was raised to $0.3225. This represents increases of 8.6%, 8.5% and 6.6%, respectively, and reflects the sustained growth in earnings over the period.

In 2002, the Company changed its financial reporting segments to conform with changes in senior management responsibilities. The gas services business and the investment in Aux Sable are included in Energy Distribution. 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:

- enhance profitability through adoption and maintenance of incentive-based rate mechanisms to maximize benefits for customers and shareholders;
- expand and extend the core liquids and gas distribution businesses through greenfield development or acquisitions; and
- develop or acquire businesses that are complementary to the core businesses.

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 the implementation of its strategy in 2002 and is committed to identifying and implementing the actions required to create value and sustainable growth.

ENERGY TRANSPORTATION NORTH

FINANCIAL RESULTS

	2002	2001	2000
	(millions of Canadian dollars)		
Enbridge System	123.7	111.1	98.3
Athabasca System	41.2	29.9	27.7
NW System	9.5	9.5	10.7
Saskatchewan System	6.4	5.9	9.5
Alliance Pipeline	40.7	37.6	28.4
Vector Pipeline	7.1	3.9	11.2
Other	7.6	7.2	6.8
	236.2	205.1	192.6

Business Activities

Energy Transportation North activities include the liquids pipelines operations in Canada and the Company's equity interests in gas transmission pipelines and AltaGas, a company engaged in natural gas gathering and processing.

The mainline pipeline, comprised of the Enbridge System and the Lakehead System (the portion of the mainline pipeline in the United States 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, the NW System and the Saskatchewan System. The Athabasca System is a 545-kilometre (339-mile) pipeline that transports synthetic and heavy oils 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. The NW System transports crude oil from Norman Wells, in the Northwest Territories, to Zama, Alberta. The Saskatchewan System consists of approximately 322 kilometres (200 miles) of trunk line and 1,920 kilometres (1,193 miles) of pipeline on three separate gathering systems in the provinces of Saskatchewan and Manitoba.

Natural gas transmission pipeline activities include equity investments in the Alliance and Vector pipelines. Enbridge owns a 37.1% interest in Alliance, a 3,000-kilometre (1,800-mile) pipeline that commenced operations in December 2000 and transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois. The Company provides operating services to and holds a 45% investment in Vector, which transports natural gas from Chicago to Dawn, Ontario. Vector also 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.

Results of Operations

Earnings from Energy Transportation North were $236.2 million for the year ended December 31, 2002, an increase of $31.1 million from 2001. The higher earnings were due to 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.

Earnings were $205.1 million for the year ended December 31, 2001, compared with $192.6 million for 2000. The higher earnings were due to increased contributions from the Enbridge System, Alliance and the Athabasca System, partially offset by lower earnings from Vector.

Liquids Pipelines

Enbridge System

In 2002, Enbridge System earnings were $12.6 million higher than last year primarily due to higher earnings from the Terrace expansion as Phase II was placed in 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.

Earnings from the Enbridge System increased to $111.1 million in 2001 from $98.3 million in 2000. The increase was mainly due to the triggering of Phase III of the Terrace Expansion in mid-2001. In the third quarter, the Company recorded a charge for an adjustment to oil inventory due to shippers of approximately $3 million, after tax. This was the result of refinements in the oil loss estimation process, as well as improvements in the accuracy of measuring oil losses as new software applications were developed.

Tolls on the Enbridge System are governed by the provisions of the Incentive Tolling Settlement (ITS). The ITS, which has been approved by the National Energy Board (NEB), has a 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 of $79.7 million have been shared approximately 54% and 46% by Enbridge and its customers, respectively. Customers also have realized an additional after-tax benefit of $5.0 million through the power guarantee mechanism of the ITS. The renewal of the ITS in 2000 resulted in a reduction of $16.0 million to the starting point revenue, providing customers with annual on-going savings of $9.0 million, after tax. Enbridge benefited by an increase of $7.6 million in the threshold earnings level from which future sharing is measured.

Athabasca System

In 2002, earnings on the Athabasca System were $11.3 million higher than 2001, primarily due to the construction of additional tankage at Fort McMurray in 2001, and the construction and completion in 2002, of the MacKay River and Christina Lake lateral lines and two additional tanks at the Athabasca terminal. With the addition of third party volumes, operational control of the Athabasca System was transferred to Enbridge from the major shipper in October 2002.

In 2001, 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 2000.

The Company has a long-term contract with the major shipper on the Athabasca System. The shipper has committed annual volumes at specified tolls over a 30-year term. The contract terms provide for tolls that are similar to those that would result under traditional cost-of-service rate-making. The contract terms also provide for a return, based on the contract volumes, that approximates the NEB's multi-pipeline rate of return on common equity in effect at the time of entering into the agreement. Additional third party volumes improve Enbridge's return beyond this level. Earnings are recognized on a cost-of-service basis and any difference between the cost-of-service revenue and cash tolls is recognized in the period. The deferred amounts will be collected over the term of the contract.

NW System

Earnings in the last three years from the NW System have been consistent and reflect the negative effect of declining rate base, offset by cost savings that generate incentive earnings. 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

Earnings have been relatively constant in 2002 and 2001. Earnings in 2000 reflect the positive impact of income tax rate reductions.

Gas Transmission Pipelines

Alliance

The increase in equity earnings of $3.1 million from Alliance in 2002, compared with 2001, was due to the acquisitions of the Williams and El Paso interests in the fourth

quarter of 2002. In 2001, equity earnings from Alliance of $37.6 million improved by $9.2 million when compared with 2000. Higher earnings resulted from a higher rate base in 2001 since construction costs were being incurred until the pipeline was placed into service in December 2000. Earnings in 2000 represent allowance for equity funds during construction (AEDC).

Vector

The contribution from Vector was $3.2 million higher in 2002, compared with 2001, due to 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 overaccrued in 2000. In 2001, Vector earnings of $3.9 million were $7.3 million less than 2000. Earnings were impacted negatively by capacity constraints in 2001, as well as higher depreciation and interest expense. In 2000, Vector was under construction and earnings represented AEDC.

OUTLOOK

Liquids Pipelines

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 involves 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 will increase capacity by approximately 140,000 barrels per day. Shippers have requested that Phase III be in service in 2003. Phase II, placed in service in 2002, and Phase III were requested by shippers to handle anticipated increases in oil sands volumes in the next few years.

Volumes transported are expected to increase in 2003 due to increased production from the oil sands region of Alberta. Fluctuations in volumes do not impact the majority of net earnings from the Enbridge System due to provisions in the ITS. The request to build Terrace Phase III demonstrates producers' confidence that more capacity out of the Western Canadian Sedimentary Basin (WCSB) will be needed in the medium term.

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

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 2003 as a result of full year operations of the MacKay River and Christina Lake facilities. In addition, the Company expects that a new diesel-loading facility, to supply the regional market of the major shipper, will be in service by the spring of 2003.

The Company has entered into a limited partnership with an industry partner to develop underground cavern facilities to provide crude oil storage services. The facilities are located near the Enbridge System main pipeline terminal at Hardisty. The partnership will provide petroleum storage services to shippers at Hardisty that previously were unavailable. The existing storage capacity of approximately three million barrels has been contracted to a shipper for a five-year term. Construction commenced in the fourth quarter of 2002, with completion expected in the fourth quarter of 2003.

Supply

Liquids supply from the WCSB is expected to increase during the next 10 years. Although supply of conventional light crude is forecast to continue to decline, significantly higher bitumen and upgraded synthetic production is expected from the Alberta oil sands region. Heavy crude production, which must be diluted with condensate, or heated or upgraded before it can be transported, may be constrained after 2006 without additional use of synthetic crude as diluent.

Conventional oil reserves in Western Canada increased in 2001 to 5.2 billion barrels. Approximately 50% of production was replaced. Reserves from the oil sands stood at 6.7 billion barrels from developed, currently producing projects or projects on which substantial investment is being made. It is estimated that there are 315 billion barrels of bitumen ultimately recoverable in the Alberta oil sands, using existing technology. To date, approximately two billion barrels have been produced.[(1)]

(1) CAPP Statistical Handbook — November 2002

Capital Expenditures

Energy Transportation North expects to spend approximately $155 million in 2003 for capital expenditures, the majority of which relates to the Terrace Phase III expansion, the cavern storage project and core maintenance.

Gas Transmission Pipelines

Earnings from Alliance should increase in 2003 as a result of Enbridge's higher ownership interest. Vector's earnings are expected to decrease as a one-time adjustment to depreciation expense increased earnings in 2002. Vector's earnings will continue to be negatively impacted over the short-term by higher interest expense. There is no near-term requirement for further capital investment in either pipeline.

In the third quarter, Enbridge purchased Williams' 9.6% and El Paso's 6.1% interests in Alliance. The acquisition from El Paso also includes its 9.5% interest in Aux Sable and Alliance Canada Marketing, which are part of Energy Distribution. Enbridge did not assume either company's direct merchant capacity commitments on the pipeline.

These purchases increase the Company's ownership interest in Alliance to 37.1% and were made at a cost of approximately $300 million.

Supply and Demand for Natural Gas [(1)]

Natural gas reserves in the WCSB increased 0.6% in 2001 to 59.8 trillion cubic feet. In 2001, approximately 106% of natural gas production was replaced. Demand for natural gas in North America is forecast to remain constant over the next five years and grow at 2% per year thereafter. Most of this growth will be for electricity generation requirements.

(1) Source: CAPP Statistical Handbook — November 2002

BUSINESS RISKS

Liquids Pipelines

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 and the price of crude oil. Drilling activity during the last three years has not been as strong as expected. The request by producers to build Phase III of Terrace, adding additional pipeline capacity, indicates that producers expect that volumes will increase in the future.

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.

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. Enbridge is assessing and evaluating the federal government's approach to implementation. Until these plans become certain, the Company will not be able to quantify the impact, if any, on its operations. The Company is encouraged by recent producer reactions to Kyoto, particularly their commitment to oil sands development, which support the outlook for the sustainability of supply for the liquids pipelines.

Regulation

Earnings from the Enbridge System and other liquid 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 65% of total western Canadian crude oil production in 2002 and provides about 75% of 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 customers. TransMountain Pipeline, Express Pipeline, and 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 its competitive tolls. The Company also offers shorter transit times from the WCSB to the U.S. Midwest.

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. However, competition to provide transportation service directly from the Alberta oil sands to Edmonton has increased.

Environment and Safety

Enbridge is committed to the protection of the health and safety of employees 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. Every five years, Energy Transportation North conducts a review of its environmental management system. The system reflects industry best practices and is aligned with the ISO 14001 standard for environmental management systems.

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.

Gas Transmission Pipelines

Alliance and Vector

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.

ENERGY TRANSPORTATION SOUTH

FINANCIAL RESULTS

	2002	2001	2000
	(millions of Canadian dollars)		
Enbridge Energy Partners	19.5	12.5	16.3
Enbridge Midcoast Energy	7.3	9.5	—
Loss on sale of Enbridge Midcoast Energy assets	(82.2)	—	—
Feeder Pipelines	8.1	9.2	7.2
Dilution gains	6.1	15.2	—
Other	(0.2)	—	(0.2)
	(41.4)	46.4	23.3

Business Activities

Energy Transportation South includes the Company's ownership interests in the operations of EEP. Enbridge is the general partner and operates the assets of EEP. Activities also include owning and operating feeder pipelines in the United States.

In October 2002, Enbridge sold the United States assets of Enbridge Midcoast Energy to EEP. Therefore, at year-end, this segment is comprised primarily of the Company's ownership interests in the Partnership. From May 2001 until October 2002, Enbridge owned 100% of Enbridge Midcoast Energy. The results of operations of Enbridge Midcoast Energy, in the table above, relate to the period when the assets were wholly-owned.

Enbridge has an effective 14.1% ownership interest (2001 — 13.6%, 2000 — 15.3%) in the Partnership. This ownership interest represents the Company's direct investment in EEP of 10.6% and an indirect investment of 3.5% through the Company's 17.2% ownership interest in EEM. EEP owns the Lakehead System, a feeder pipeline in North Dakota, the Enbridge Midcoast Energy assets and natural gas gathering and processing assets in east Texas (East Texas System).

Results of Operations

Results for the year ended December 31, 2002 were a loss of $41.4 million, compared with earnings of $46.4 million for 2001. The 2002 results include an after-tax loss of $82.2 million on the sale of the Enbridge Midcoast Energy assets. Excluding this loss, earnings for 2002 were $5.6 million lower than 2001. Increased earnings from the Partnership, resulting from the acquisitions of the North Dakota and East Texas Systems and the Enbridge Midcoast Energy assets, were more than offset by lower earnings from Enbridge Midcoast Energy prior to the sale and higher dilution gains in 2001. Enbridge Midcoast Energy earnings reflected improved operating performance from the assets, 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. The prior year included dilution gains of $15.2 million, compared with $6.1

million in 2002, reflecting two unit issuances by EEP in 2001, compared with one in 2002.

In 2001, earnings from Energy Transportation South increased by $23.1 million in 2001 to $46.4 million. The acquisition of Enbridge Midcoast Energy in May 2001 and dilution gains on the Company's investment in EEP were the major contributors to the increase. Earnings from the Partnership were lower in 2001 due to reduced throughput, an adjustment to oil inventory due to shippers and one-time costs associated with relocating the Partnership's office to Houston.

In October 2002, the Company closed the sale of the United States assets of Enbridge Midcoast Energy to EEP for consideration of US$820.0 million, including cash and the assumption of 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 the Partnership 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 the Partnership improved in 2002 due to higher incentive earnings earned by Enbridge as the general partner, improved results from the Lakehead System and a higher ownership interest in the fourth quarter. The acquisitions of the North Dakota and East Texas Systems contributed a full year's earnings and the acquisition of the Enbridge Midcoast Energy assets increased earnings in the fourth quarter.

The decreased contribution from the Partnership in 2001 compared with 2000 resulted from reduced throughput, an adjustment to oil inventory due to shippers, as well as one-time costs associated with relocating the Partnership's office to Houston.

In December 2001, EEP completed the acquisition of the East Texas System for US$230 million. The acquisition of the East Texas System represented the Partnership's entry into the natural gas transportation business.

Enbridge Midcoast Energy

Enbridge Midcoast Energy was sold to EEP in October 2002. Enbridge purchased Midcoast Energy Resources, Inc. in May 2001 for cash consideration of $561.8 million and the assumption of long-term debt. Earnings from Enbridge Midcoast Energy in 2002 were $7.3 million, a decrease of $2.2 million from the prior year. While 2002 reflects improved operating performance, this was 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 closed the acquisition of natural gas gathering and processing facilities in northeast Texas for approximately $290 million. Also, in October 2001, Enbridge announced the purchase of natural gas gathering, treating and transmission assets in south Texas for US$50 million. The Company closed a portion of the acquisition for US$9 million and EEP now holds an option to purchase the remaining assets. These assets were included with Enbridge Midcoast Energy and were part of the October 2002 sale to EEP.

OUTLOOK

Enbridge Energy Partners

Earnings for the Partnership are expected to increase in 2003, reflecting higher transportation volumes on the Lakehead System and improved performance from the East Texas System. In addition, a full year's contribution from the Enbridge Midcoast Energy assets is expected to increase earnings. 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 the Partnership's earnings. The growth in the asset base and expected increase in earnings should result in higher incentive distributions to the Company.

The Terrace Phase III expansion, currently underway, offers opportunities to increase volumes transported on the Lakehead System as crude oil supply from Western Canada increases due to oil sands development. Phase III is designed primarily to increase capacity between Clearbrook, Minnesota and Superior, Wisconsin by approximately 140,000 barrels per day. The estimated cost of this project to EEP is approximately $312 million and is planned to be in service in 2003.

Capital Expenditures

In 2003, the Company plans to spend $17 million related to additional investments in EEP and EEM.

BUSINESS RISKS

Virtually all of the Company's operations in Energy Transportation South are carried out through the Partnership. The business risks are mitigated by the size of the Company's investment in the Partnership.

Supply and Demand

The Lakehead System is dependent upon the level of supply of and demand for crude oil and other liquid hydrocarbons from Western Canada. A decreased supply of crude oil impacts deliveries with a corresponding impact on earnings.

Certain of the Partnership's natural gas gathering assets are 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

The interstate and intrastate gas pipelines are subject to regulation by FERC or state regulators. Gas gathering currently is not subject to active regulation. Several of the Partnership's assets are regulated by FERC and their revenues could decrease if tariff rates were protested. Kansas Pipeline Company (KPC), has recently lowered its rates in compliance with a FERC order. Enbridge has agreed to reimburse EEP for a shortfall in revenue approximating US$2 million for the next two years. The rates are subject to a rehearing by FERC. Certain states in the U.S. may initiate rate regulatory oversight of intrastate gas pipelines. If this regulation occurs, it may reduce the revenues and earnings of the Partnership.

Several of the Partnership's pipeline systems transport commodities that are hazardous if released from the pipeline system. These assets are subject to strict regulation and could be shut down or required to operate at reduced operating pressures that likely would reduce earnings.

Market Price Risk

The Partnership'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.

ENERGY DISTRIBUTION

FINANCIAL RESULTS

	2002	2001	2000
	(millions of Canadian dollars)		
Enbridge Gas Distribution	85.3	156.1	147.6
Enbridge Commercial Services	10.7	14.3	18.4
Noverco	20.6	16.3	31.4
Enbridge Gas New Brunswick	3.6	2.3	3.4
Gas Services	(7.8)	(5.3)	(8.8)
Aux Sable	(3.1)	(6.2)	(3.3)
Other	4.5	4.3	14.5
	113.8	181.8	203.2

Business Activities

Energy Distribution includes the gas distribution operations of Enbridge Gas, Enbridge Commercial Services, which owns the Company's investment in CustomerWorks LP, 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, and the equity investment in Aux Sable.

Enbridge Gas is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.6 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).

Enbridge Commercial Services commenced operations on January 1, 2000 to provide information technology, fleet services, call management centre, customer care and billing services to Enbridge Gas, the Energy Services business and others. In 2001, Enbridge and BC Gas Inc. formed CustomerWorks LP to provide service covering the entire meter-to-cash process, including many of the services provided by Enbridge Commercial Services. Operations commenced on January 1, 2002. CustomerWorks LP provided services to more than 3.5 million customers of the BC Gas utility and Enbridge's gas distribution business. In August 2002, CustomerWorks LP 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, 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 constructed a new distribution system and has approximately 1,600 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 $113.8 million for the year ended December 31, 2002, compared with $181.8 million in 2001. Lower earnings in 2002 were attributable to warmer weather experienced in the Enbridge Gas franchise area in 2002 and a lower contribution from Enbridge Commercial Services, partially offset by improved earnings from Noverco. Earnings for 2001 included the positive impact of income tax rate reductions of $45.0 million.

Earnings from Energy Distribution were $181.8 million for the year ended December 31, 2001, compared with $203.2 million in 2000. The results reflect strong operating performance from Enbridge Gas, more than offset by a smaller positive impact of tax rate reductions in 2001 than in 2000. Earnings from Noverco were lower in 2001 due to the positive effect of tax rate reductions on earnings in 2000.

Enbridge Gas

Earnings from Enbridge Gas decreased by $70.8 million in 2002 from 2001. The decrease was due to significantly lower gas distribution margins, caused by lower distribution volume resulting from warmer weather. Had Enbridge Gas experienced normal weather in its franchise area, earnings would have been higher by $29.3 million. Normal weather is the weather forecast by Enbridge Gas, 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 non-GAAP measure is unique to the Company and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other companies. The weather-normalized adjustment is consistent with the manner in which degree days are calculated for regulatory purposes.

Earnings in 2001 of $156.1 million were higher than 2000 by $8.5 million. Although weather for 2001 was slightly warmer in the franchise area, it was colder during the winter months when distribution margins are higher, resulting in higher earnings of approximately $5.0 million. Operating earnings also increased due to growth in the customer base and lower unaccounted for gas, which is the difference between distribution volume entering the system and volume delivered to customers. The weather was 5% colder compared with 2000 and was slightly warmer than normal.

In the rate-making process, the OEB approves revenue rates that are designed to recover the cost of providing service and to provide a return on equity. Rates are set on a forecast basis. The cost of providing service includes the cost of gas commodity purchases and transportation costs, operation and maintenance costs, depreciation, income taxes, and the cost of capital used to finance all assets used in gas distribution, storage and transmission. The cost of capital, which is expressed as an allowed rate of return on rate base, is designed principally to meet the cost of interest on long and short-term debt, satisfy the dividend requirements of preferred shareholders, and provide a return on investment on common equity. It is the responsibility of Enbridge Gas to demonstrate to the OEB the prudency of the costs it has incurred or the activities it has undertaken. Enbridge Gas does not profit from the sale of the natural gas commodity.

Enbridge Gas continued to operate under a targeted Performance-based Regulation plan (PBR plan), which expired at the end of fiscal 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; these were offset by an annual productivity credit of 1.1%. The PBR plan also allowed for the recovery, subject to OEB approval, of factors impacting operation and maintenance costs that are outside of management's control. During the PBR plan period, Enbridge Gas retained the savings it achieved as operation and maintenance expenses were lower than those calculated under the formula.

The allowed rate of return on common equity for Enbridge Gas is based on the yield on Canadian government long-term bonds. For 2002, the allowed rate of return was 9.66% (2001 — 9.54%, 2000 — 9.73%) on a deemed common equity ratio of 35%.

Over the last three years, Enbridge Gas added 157,000 customers, including approximately 52,000 customers in 2002. This growth was attributable to the continued preference for natural gas among homeowners and builders due to the price advantage and environmental benefits over other forms of energy. The new residential housing market was strong in 2002 and 2001 and, through marketing programs, builders have continued to choose natural gas for new housing construction.

Enbridge Commercial Services

The contribution from Enbridge Commercial Services (ECS) was $10.7 million for the year ended December 31, 2002, a decrease of $3.6 million compared with the prior year. The decrease is due to the positive impact of tax rate reductions in 2001 and the transfer of the remaining ECS operations into Enbridge Gas in the fourth quarter.

Lower earnings from ECS in 2001, compared with 2000, reflect the transfer of the merchandise finance plan to the Energy Services business effective January 1, 2001. The merchandise finance plan business is included as a component of discontinued operations.

Noverco

The contribution from Noverco was $20.6 million in 2002, compared with $16.3 million in 2001. The increase is due to lower financing costs and higher incentive earnings. Equity earnings from Noverco in 2001 were lower than 2000, mainly due to the positive impact of tax rate reductions in 2000.

Variations from normal weather do not affect Noverco's earnings as the utility 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 4.45%. The weighted average dividend yield on the preference shares, which is reset annually, was approximately 10% for each of the last three years.

Enbridge Gas New Brunswick

Earnings from Enbridge Gas New Brunswick improved in 2002 as a result of a full year of operations. Customer attachment to the new facilities continued to be slower than expected largely due to the shortage of skilled workers to install heating, ventilation and air conditioning equipment. This has resulted in an increase in the regulatory receivable used during the development period to defer annual shortfalls between EGNB's revenues and cost of service. This deferral is anticipated to be significantly higher than expected at the project's commencement. The recovery of this deferral will be determined by the regulator at the end of the development period.

Earnings in 2001 were slightly lower than 2000. Construction of new natural gas distribution facilities commenced in the third quarter of 2000. Customer attachment to the new facilities has been slower than expected, resulting in lower earnings in 2001. Earnings in 2000 consisted mainly of AEDC.

Gas Services

Gas Services experienced a loss of $7.8 million for the year ended December 31, 2002, compared with a loss of $5.3 million in 2001. The loss increased in 2002 because of reduced basis differentials between Alberta and Chicago and between Chicago and Dawn, Ontario. The basis differential is the cost of transportation between natural gas hubs and determines the revenue which can be obtained from transportation capacity. The loss in 2001 was attributable to losses on the Company's Alliance and Vector merchant capacity, also from the narrowing of the basis differential.

Aux Sable

Enbridge owns a 30.9% 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 2002, the loss from Aux Sable was $3.1 million, an improvement of $3.1 million from the loss of $6.2 million incurred for the year ended December 31, 2001. The improvement is due to improved margins between the prices of natural gas liquids and natural gas in

2002. In 2001, Aux Sable generated a loss of $6.2 million due to the unfavourable spread between gas liquids and natural gas prices during the first half of the year. The facilities operated at a break-even level during the last half of 2001.

OUTLOOK

Enbridge Gas Distribution

2003 Rate Application

Enbridge Gas has filed its 2003 rate application with the OEB, requesting an order to approve rates for the sale, distribution, transmission and storage of gas, which reflected a gross revenue deficiency, or proposed increase in revenue rates, of $101.7 million. Of this amount, approximately $9.0 million is associated with changes to the distribution volume forecast, gas in storage inventory valuation and cost of capital (including the application of the OEB-approved rate of return on common equity formula), offset somewhat by a decline in federal taxation rates. A further $43.8 million of the increase arises from a requested increase in operating and maintenance expense recovery and $13.0 million from the proposed mechanism for recovery of the regulatory receivable related to the unbundling of the Energy Services business. The remainder relates to variances in all other items requested for recovery in the application. The 2003 rate application is a traditional cost-of-service application as the PBR plan ended in 2002. It is expected that the application will be heard by the OEB in early 2003 and a decision is anticipated in the third quarter of 2003.

The 2003 rate application includes a request to review and revise the current formula used to calculate the rate of return on common equity. It is anticipated that this request will be heard in a separate phase of the 2003 rate hearing and, as such, the increase to a proposed rate of return of 11.5% versus the 9.95% produced by the current formula has not been incorporated into the calculation of the $101.7 million deficiency. The increase in the requested rate of return reflects the Company’s need to compete for investment dollars in the North American marketplace.

Regulatory Receivable

In a prior rate case, the OEB approved the recovery of $50.0 million of future income taxes related to the water heater rental business that was transferred to the Energy Service business in 1999. As part of its 2002 rate case, the Company applied for a mechanism to recover a portion of the $50.0 million. This aspect of the Company’s application was deferred and the regulatory process is underway.

Incentive Regulation Plan

The trend in North America is toward incentive, or performance-based, regulation. Enbridge Gas has completed its three-year, OEB-approved targeted PBR plan. The OEB expects Enbridge Gas to develop, in consultation with stakeholders, an appropriate incentive regulation plan. Enbridge Gas has provided a proposal for an incentive regulation plan to stakeholders for the purposes of discussion. For fiscal 2003, Enbridge Gas has filed a cost-of-service rate application with the OEB, which would be used to establish the base year rates for the incentive regulation term. The

proposal suggests that rates be adjusted annually by a consumer price index and that utility earnings above or below the OEB-approved return on common equity be shared equally between ratepayers and Enbridge. Enbridge Gas has proposed that certain costs, such as gas commodity costs and capital expenditures for the safe operation and maintenance of the distribution system, should be passed through to ratepayers outside of the calculated rates. Enbridge Gas is holding discussions currently with stakeholders, the outcome of which may result in changes to the proposal. The plan will be presented to the OEB following the establishment of base rates for 2003.

2002 Rates Decision

The OEB approved the 2002 revenue requirement and final rates in August 2002. In December 2002, the OEB released its decision with respect to several policy issues stemming from the 2002 rate case. The OEB's decision included concerns and questions about the Company's business operations in regards to outsourcing agreements, including the pipeline transportation contract with Alliance, as well as the agreements with Enbridge and its affiliates. As Enbridge Gas does not accept some aspects of the decision, it has filed a notice of motion, requesting the OEB to review its decision on Alliance and affiliate outsourcing, or in the alternative in this latter matter, to conduct a generic hearing on rules for affiliate outsourcing. Enbridge Gas also has filed an appeal to the Divisional Courts on matters arising from what Enbridge Gas believes to be errors in law in the decision.

Direct Purchase

Deregulation of the natural gas industry has introduced many changes to the natural gas distribution business, one of which occurred in the gas marketing segment of the industry. Prior to the advent of deregulation in 1985, Enbridge Gas supplied natural gas to 100% of its customer base. In 2002, 759,000 customers purchased their supply of gas from sources other than the utility (2001 — 695,000, 2000 — 602,000). Earnings are not impacted by the customers' choice of gas commodity supplier, provided any migration is accurately forecast in advance and incorporated in the volume underlying the rate application. Enbridge Gas intends to continue to provide customers the option of purchasing their natural gas directly from the utility.

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 currently is not permitted under provincial legislation. The Company believes that the government of New Brunswick will be receptive to its plans.

Capital Expenditures

Capital expenditures for the Energy Distribution business are expected to be approximately $322 million. The majority of the expenditures relate to expansion of and core maintenance on the Enbridge Gas distribution system. In addition, expansion of the Enbridge Gas New Brunswick distribution system will continue.

BUSINESS RISKS

Enbridge Gas Distribution

The business risks inherent in the natural gas distribution industry impact the ability of Enbridge Gas 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. With the ongoing changes in the electricity industry, Enbridge Gas may face an emerging risk of increased competition in the energy market.

The regulatory process in North America has been evolving in recent years towards incentive or performance-based regulation and away from traditional cost-of-service regulation. Since the PBR plan only applied to operation and maintenance expenses, it did not materially change existing business risks. It is Enbridge Gas' intention to introduce a comprehensive form of incentive regulation for 2004. It is anticipated that this form of regulation will provide greater opportunity to earn in excess of the allowed rate of return, but, as a result, may impact business risk.

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 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. 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 Enbridge Gas attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables. The mix of sales and transportation of gas for customers and the mix between the higher margin residential and commercial sectors and lower margin industrial sector could impact results. The timing of gas sales is also a factor, as the winter season has higher rates than the summer season.

During 2002, Enbridge Gas received approval from the OEB to defer the difference between forecast and actual unaccounted for gas. Unaccounted for gas is the difference between volume entering the distribution system and that delivered to

customers, determined based on meter readings. The difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition.

Rate Relief

Enbridge Gas 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. Enbridge Gas monitors the balance and its potential impact on ratepayers and will request interim rate relief that will allow it to recover or refund the gas commodity cost differential. Rate relief can also be sought for other significant unbudgeted amounts, allowing Enbridge Gas to recover the costs of providing and maintaining the quality of its service while achieving the allowed rate of return on rate base.

Enbridge Gas implemented a quarterly rate adjustment mechanism starting in 2002. This allows for the quarterly adjustment of rates to reflect changes in natural gas commodity prices. Adjustments are subject to approval by the OEB.

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, reliability of the forecasting process should ensure 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 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 unfavourable spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. Equity earnings would be negatively impacted by a decrease in the spread and positively impacted by an increase in the spread.

INTERNATIONAL

FINANCIAL RESULTS

	2002	2001	2000
	(millions of Canadian dollars)		
OCENSA/CITCOL	35.3	35.1	30.3
CLH	33.3	—	—
Jose Terminal	3.2	5.9	1.5
Consulting, business development costs and other	(3.8)	(5.4)	(5.4)
	68.0	35.6	26.4

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 as operator of the Jose Terminal in Venezuela and from technology and consulting services provided by Enbridge Technology Inc.

In the first quarter of 2002, the purchase of a 25% interest in CLH, for approximately $430 million was completed. Enbridge has a role in management of CLH through Board representation and the appointment of management positions.

Results of Operations

Earnings increased by $32.4 million to $68.0 million in 2002. The acquisition of CLH in the first quarter of 2002 represented the growth in International. Earnings from other operations approximated 2001.

Earnings in 2001 increased by $9.2 million to $35.6 million. The increase was partially due to the additional OCENSA ownership interest acquired in the third quarter of 2000. In addition, higher fees were earned to operate the Jose Terminal, resulting from the new long-term operating contract finalized in the second quarter of 2001.

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/reward. The technology and consulting business is expected to provide support in connection with identification and development of equity participation projects.

The Jose Terminal long-term operating agreement has been in a force majeure situation since December 2002 as a result of the political uncertainty in Venezuela. The Venezuelan military and the Ministry of Energy and Mines are currently in control of the

terminal facilities. Discussions are continuing with PDVSA, the national oil company, to return the operating company, in which Enbridge holds a 45% interest, to its role under the operating agreement. In the event the operating role is not re-established, the contract provides for certain payments to the operator.

Historically, International has focussed on “grass roots” infrastructure 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 investment and acquisition opportunities. Opportunities will be evaluated against the Company’s established investment criteria. Latin America and Western Europe are key regions of interest. Enbridge plans for the International segment to contribute approximately 15% of 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 contractual arrangements, operation of the assets, regular analysis of country risk, and foreign currency hedging and insurance programs.

CORPORATE

	2002	2001	2000
	(millions of Canadian dollars)		
Corporate Financing	(64.9)	(70.4)	(59.0)
Other	22.5	14.7	(28.8)
	(42.4)	(55.7)	(87.8)

The Corporate segment includes new business development activities and corporate financing costs.

Corporate costs amounted to $42.4 million in 2002, a decrease of $13.3 million from 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. In addition, corporate activities contributed less in 2002 than in 2001 and business development activities increased in 2002.

Corporate costs totalled $55.7 million in 2001, compared with $87.8 million in 2000. Higher financing costs associated with investments made late in 2000 and the acquisition of Enbridge Midcoast Energy in May 2001 were incurred during the year. These costs are not allocated to the business operations. Corporate activities also generated improved results in 2001. In 2000, the Company recorded a loss on foreign exchange contracts of $15.6 million, after tax, and income tax expense related to tax rate reductions.

In December 2000, the federal government substantively enacted a 6% reduction in corporate tax rates. As a result, certain of the Company's anticipated U.S. dollar cash flows became overhedged for accounting purposes. The derivative financial instruments were valued at market prices and a loss of $15.6 million was charged to income in 2000. The forward foreign exchange contracts subsequently were designated as a hedge of certain of the Company's equity net investments in the United States in the third quarter of 2001.

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.

Earnings from discontinued operations were $45.3 million in 2001, compared with earnings of $34.6 million in 2000. The increase is attributable to growth in the business, particularly the water heater rental program.

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, are expected to be sufficient to satisfy liquidity requirements.

One of the Company's objectives in 2002 was to reduce its debt to equity ratio and, therefore, strengthen its balance sheet. This objective was achieved. The debt to equity ratio, including short-term borrowings, at December 31, 2002, was 64.4%, compared with 72.9% at the end of 2001. The reduced leverage was primarily a result

of the proceeds received on the sales of the Energy Services business and the Enbridge Midcoast Energy assets.

The most significant transaction affecting both investing and financing activities in 2002 was the sale of the Enbridge Midcoast Energy assets for US$820 million. The Company received cash proceeds of $529.3 million. The remaining consideration was in the form of assumed debt owing to the Company. Concurrent with the sale transaction, EEM completed a public offering of 9,000,000 shares, including 1,550,000 shares purchased by Enbridge. The net proceeds of $421.9 million were used to purchase i-units in EEP. The statement of cash flows includes the proceeds of EEM's issuance of shares and investment in EEP, because EEM is a subsidiary of the Company. The 82.8% interest in EEM not held by Enbridge is displayed as non-controlling interests on the consolidated statement of financial position. The Company's consolidated leverage is expected to improve further through reductions in the assumed affiliated debt as EEP secures additional financing.

Operating Activities

Cash provided by operating activities before changes in operating assets and liabilities and cash from discontinued operations, was $732.7 million for the year ended December 31, 2002, compared with $735.7 million and $599.8 million for 2001 and 2000, respectively.

In 2002, cash from operations is 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 loss on sale of the Enbridge Midcoast Energy assets and higher future income tax expense.

The increase in cash from operations in 2001 was attributable to higher earnings and a decreased level of non-cash credits. The lower non-cash credits reflected smaller future income tax recoveries resulting from tax rate reductions and increased cash distributions from Alliance and Vector consistent with operations commencing in late 2000.

The decreased funding requirements for operating assets and liabilities in 2002 was due to lower gas in storage and decreased accounts receivable, commensurate with the lower cost of gas in 2002. In 2001 and 2000, working capital funding was required to fund an increase in gas in storage that resulted from the higher commodity cost for natural gas. The higher cost of gas also increased accounts receivable balances in the gas distribution business.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2003.

Investing Activities

Cash used in investing activities for the year ended December 31, 2002 was $251.7 million, compared with $1,621.7 million in 2001 and $949.8 million in 2000.

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, in addition to capital expenditures in Energy Transportation North and Energy Distribution, represent the majority of the cash used for investing purposes and more than offset the cash inflows from the sales of the Enbridge Midcoast Energy assets and the Energy Services business. Capital expenditures in Energy Transportation North primarily related to construction of new facilities on the Athabasca System. Energy Distribution capital expenditures included capital maintenance and expansion of the gas distribution system. Cash provided from investing activities includes proceeds from the sale of marketable securities and partial repayment by EEP of short-term loans required to finance acquisitions.

Activity in 2001 was the result of acquisitions, including Midcoast Energy Resources, a greater interest in Frontier Pipeline, and gathering assets in South Texas, as well as a short-term loan to EEP to bridge finance an acquisition. There were increased additions to property, plant and equipment during 2001, which included the construction of Terrace Phase II and the Athabasca System facilities expansion, capital maintenance and expansion of the gas distribution business, and the capital program of Enbridge Midcoast Energy subsequent to acquisition. These were offset, in part, by significantly reduced long-term investment activity, as Alliance and Vector construction was completed in late 2000.

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.

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.

In 2001, cash provided from financing activities was greater than 2000 to support the increased levels of investing activity, primarily through acquisition, and higher capital expenditures. Investing activity was financed primarily with short-term variable rate debt on an interim basis.

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 the Canadian dollar exchange rate relative to other currencies and interest rates. 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 12 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, futures, options and collars to manage physical exposures that arise from the merchant capacity commitments on Alliance and Vector. 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 Enbridge Gas 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.

SUPPLEMENTARY INFORMATION

(unaudited)

Selected Quarterly Financial Data
2002

	First	Second	Third	Fourth	Total
	(millions of dollars, except per share amounts)				
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
Dividends per common share	0.71	2.74	(0.03)	0.18	3.60
	0.38	0.38	0.38	0.38	1.52

2001

	First	Second	Third	Fourth	Total
Operating revenue from continuing operations	778.8	1,615.9	974.7	711.5	4,080.9
Operating income from continuing operations	192.7	371.9	92.4	89.5	746.5
Earnings applicable to common shareholders					
Continuing operations	79.8	245.3	58.4	29.7	413.2
Discontinued operations	3.7	25.1	6.4	10.1	45.3
	83.5	270.4	64.8	39.8	458.3
Earnings per common share					
Continuing operations	0.51	1.56	0.37	0.19	2.63
Discontinued operations	0.02	0.16	0.04	0.06	0.28
	0.53	1.72	0.41	0.25	2.91
Dividends per common share	0.35	0.35	0.35	0.35	1.40

Quarterly Share Trading Information
The Toronto Stock Exchange
2002

	First	Second	Third	Fourth
	(dollars)			
High	46.15	48.94	49.25	46.85
Low	41.50	43.06	42.71	41.11
Close	44.73	47.16	46.27	42.61
Volume (millions)	21.3	15.5	17.0	18.5

2001

	First	Second	Third	Fourth
	(dollars)			
High	43.00	42.50	43.24	45.55
Low	33.90	35.55	39.02	40.89
Close	42.35	41.19	42.55	43.40
Volume (millions)	20.7	17.7	13.3	16.0

The New York Stock Exchange and the NASDAQ National Market[1)]
2002

	First	Second	Third	Fourth
	(U.S. dollars)			

High	27.57	30.49	31.03	29.14
Low	24.20	25.61	26.29	26.05
Close	26.52	30.11	28.37	26.73
Volume (millions)	0.6	0.6	1.7	1.3

	2001			
	First	Second	Third	Fourth
	(U.S. dollars)			
High	28.63	27.20	27.50	28.77
Low	22.25	23.00	25.50	26.05
Close	26.69	27.14	26.94	27.22
Volume (millions)	0.2	0.3	0.5	0.7

1) Effective October 30, 2001, Enbridge Inc. began trading on the New York Stock Exchange and delisted from the NASDAQ.

Exhibit 4

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 27, 2003, relating to the financial statements of the Corporation as at December 31, 2001 and 2002 and for the years then ended, which report is included in Exhibit 2 to this Annual Report on Form 40-F of the Corporation.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta
January 27, 2003