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

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FINANCIAL

FORM 6-K

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

Dated March 26, 2004
Commission file number 0-21080

ENBRIDGE INC.
(Exact name of Registrant as specified in its charter)

Canada
(State or other jurisdiction
of incorporation or organization)

None
(I.R.S. Employer Identification No.)

3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of principal executive offices and postal code)

MAR 29 2004

(403) 231-3900
(Registrants telephone number, including area code)

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

Form 20-F ______ Form 40-F ✓

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

Yes ______ No ✓

The following document is being submitted herewith:

1. Annual Report for the year ended December 31, 2003.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date: March 26, 2004 By: ______________________

Blaine G. Melnyk
Corporate Secretary &
Associate General Counsel

Consistent Continental Growth

2003 Annual Report

Enbridge is an energy delivery company, as such, we provide an essential service for our customers. We deliver crude oil and natural gas to heat homes, power transportation systems, and provide fuel and feedstock for industries. Our vision is to be North America's leading energy delivery company while adding long term value for our shareholders. In 2003, we expanded our continental footprint in North America by acquiring additional energy delivery assets and announcing a number of new projects for future growth and expansion.

— Patrick D. Daniel, President & Chief Executive Officer

The cover of this year's annual report, and the other illustrations in the book, are the work of artist Pascal Milelli, an internationally-recognized illustrator based in Western Canada and a graduate of The Alberta College of Art & Design. Pascal's paintings capture and combine the vitality of the people of Enbridge with the Company's diverse portfolio of energy delivery assets.

The photographs used in this report also reflect that successful combination of people and assets, and represent all of the Company's business segments, throughout North America and internationally. Quality people and quality assets, coming together "where energy meets people" — that's Enbridge.

Dividends Per Common Share

(dollars per share)

03	1.660
02	1.520
01	1.400
00	1.270
99	1.195
98	1.120
97	1.060
96	1.015
95	1.000
94	1.000

94 95 96 97 98 99 00 01 02 03

Earnings Per Common Share

(dollars per share)

03	4.030
02	3.600
01	2.910
00	2.540
99	1.910
98	1.660
97	1.580
96	1.450
95	1.150
94	0.545

94 95 96 97 98 99 00 01 02 03

Financial *(millions of Canadian dollars, except per share amounts)*	**2003**	2002	2001
Earnings Applicable to Common Shareholders			
Continuing Operations	**667.2**	334.2	413.2
Discontinued Operations	–	242.3	45.3
	667.2	576.5	458.5
Per Common Share Amounts			
Earnings — Continuing Operations	**4.03**	2.09	2.63
Earnings — Discontinued Operations	–	1.51	0.28
	4.03	3.60	2.91
Dividends	**1.66**	1.52	1.40
Common Share Dividends Paid	**283.9**	251.1	227.5
Return on Average Common Shareholders' Equity	**19.9%**	19.9%	18.6%
Debt to Debt Plus Shareholders' Equity at Year End	**61.4%**	64.4%	72.9%

Operating	**2003**	2002	2001
Liquids Pipelines [1]			
Deliveries *(thousands of barrels per day)*	**2,189**	2,088	2,109
Barrel miles *(billions)*	**710**	705	695
Average haul *(miles)*	**889**	925	903
Gas Distribution [2]			
Volume of gas distributed *(billion cubic feet)*	**458**	410	427
Number of active customers *(thousands)*	**1,679**	1,623	1,571
Degree day deficiency [3] *(degrees Celsius)*			
Actual	**4,029**	3,362	3,766
Forecast based on normal weather	**3,565**	3,700	3,816

1 *Liquids Pipelines operating highlights include the statistics of the Lakehead System and wholly owned liquid pipeline operations.*

2 *Highlights of Gas Distribution reflect the results of Enbridge Gas Distribution and other gas distribution operations on a quarter lag basis for the years ended September 30, 2003, 2002 and 2001. Energy Distribution volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

3 *Degree day deficiency is a measure of coldness. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Toronto area.*

Enbridge is well positioned to capitalize on future growth opportunities as a result of another very strong year in 2003.

Donald J. Taylor, Chair *(left)*
and **Patrick D. Daniel**, President & Chief Executive Officer

Earnings grew to a record $667.2 million in 2003, or $4.03 per common share, including gains on sale of assets. Removing gains and other unusual items, earnings were $2.84 per common share, up another 6.4% from one year ago. All five operating segments — crude oil pipelines, natural gas distribution systems, natural gas pipelines, international operations, and our two sponsored investments (Enbridge Energy Partners in the U.S. and Enbridge Income Fund in Canada) — reported increased earnings. This growth was accomplished while debt to total capitalization was reduced and A-level credit ratings were confirmed with stable outlooks.

During the year, the Company also celebrated its 50th anniversary as a publicly traded entity, having provided a 13.1% compound annual shareholder return over that period of time. This sustained, consistent performance in providing the "energy bridge" between energy suppliers and energy consumers is what best defines your Company.

As a result of the Company's past performance, Enbridge started 2004 in the strongest relative position in its history. The balance sheet is strong, the business model is proven and stable, and the Company is geographically well located to expand and extend its role in delivering energy to customers in North America and internationally.

Achievements in 2003

Our crude oil pipeline system grew significantly in 2003, as we completed the Phase III Terrace expansion on our crude oil mainline. We put into service Canada's first underground crude oil storage facility at Hardisty, Alberta. We also acquired a pipeline that currently runs from Cushing, Oklahoma to Chicago and plan on reversing it to transport Western Canadian crude further south into the strong U.S. Midcontinent market. This "Spearhead" project, coupled with Enbridge Energy Partners' new proposal for the Southern Access line from Superior, Wisconsin, to Wood River, Illinois, will broaden markets for Canadian producers and improve access by American consumers to the huge oil sands reserves of Western Canada. Enbridge intends to further expand that access with future pipelines to the U.S. Gulf Coast, eastern PADD II region of the U.S. Midwest, and the Canadian West Coast (our Gateway Project).

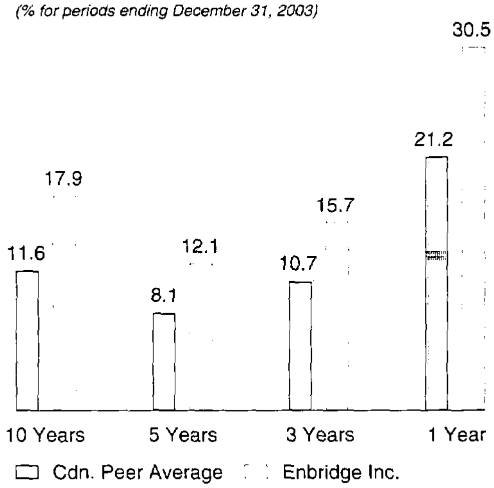
In 2003, we set a record by adding more than 60,000 new customers to our gas distribution network in Ontario, which is one of the most cost-efficient gas distribution systems in North America. Enbridge has proven in its liquids transportation business that it can provide additional benefits to its customers and shareholders through implementation of incentive rate-setting mechanisms. In Ontario, however, a common understanding and cooperation among regulators, distribution customers and Enbridge will be required to achieve this. In 2004, we will work with these parties to advance this understanding.

Five years ago Enbridge marked its entry into the natural gas pipelining business. In a short period of time we have built a very strong position in the corridor serving the U.S. Midwest and Eastern Canadian markets with Western Canada gas supply. In 2003, we increased our interest in the Alliance Pipeline to 50% and in the Vector Pipeline to 60%. In addition, Enbridge Energy Partners acquired gas gathering and processing assets in North Texas, which complement the Partnership's existing East Texas assets and growing presence in the U.S. Gulf Coast states and Midwest; and announced plans to acquire crude oil and liquids pipeline and storage systems in the Midcontinent region, including the Ozark Pipeline which transports crude oil from Cushing to Wood River.

In the U.S., our growth continues to be led by Enbridge Energy Partners, which has grown into a large master limited partnership with geographic and commodity diversity. In Canada, we successfully launched Enbridge Income Fund, already a premier Canadian income fund with a low-risk profile focused on pipeline transportation assets. Both entities are self-financing vehicles with proven low-cost capital, and we expect them to play major roles in the future acquisition of mature energy delivery assets in their respective countries.

Total Shareholder Return

(% for periods ending December 31, 2003)



Future growth opportunities

Enbridge is focused on delivering energy to meet the needs of consumers and society in general. As a large, successful corporation we have a responsibility to conduct our business to very high standards of integrity, transparency, safety and environmental protection. We consider it our responsibility to continue to earn the right to do business in the countries and communities in which we operate.

With our strong financial position and growing portfolio of assets in key markets, Enbridge is uniquely positioned to deliver new supplies of oil and gas to meet growing market demand. Enbridge is specifically committed to:

- Broadening markets for Canadian oil (particularly crude oil from Alberta's oil sands) and helping ensure security of supply for U.S. and other consumers. We have many excellent projects ahead of us, and we are working with our customers to identify continental opportunities and propose new delivery solutions.

- Increasing security of supply and ensuring an effective price mechanism for natural gas consumers in Ontario, at the same time as we operate one of the most cost-efficient distribution businesses in the world.

- Ensuring North American natural gas markets continue to have sufficient supplies to meet their needs. This could include participation in Liquefied Natural Gas (LNG) projects and pipeline projects to connect frontier supply basins.

- Helping producers receive fair netbacks for their natural gas production by debottlenecking areas such as the U.S. Rockies, and the Barnett Shale and Bossier gas play areas of Texas.

- Building and operating international pipelines like those in Colombia and Spain that generate attractive rates of return and complement our North American base of operations.

In conclusion

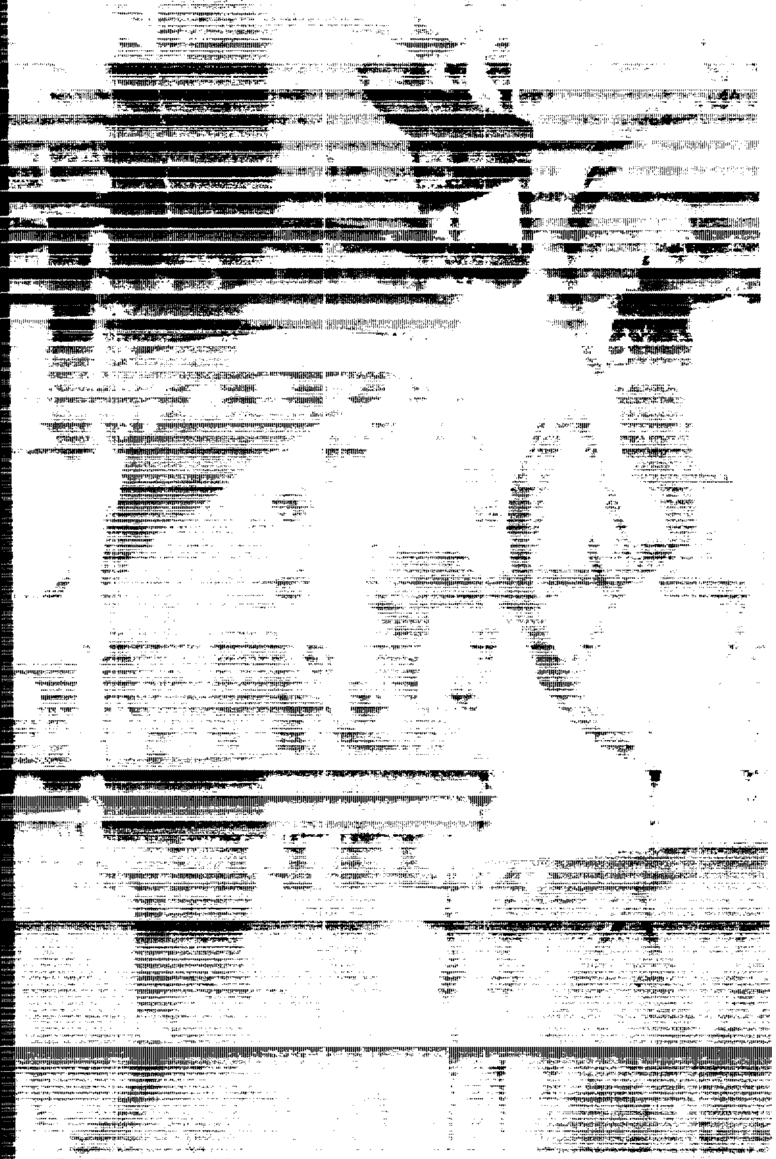
We thank Enbridge's Board of Directors for their ongoing support and counsel. And we thank Michel Gourdeau, one of our Directors who left the Board in 2003, for his contributions.

We also thank all of our employees for their continued hard work and commitment to excellence. At Enbridge we pride ourselves on being superior asset managers, recognizing that it is truly the combination of quality assets and quality people that has made Enbridge successful.

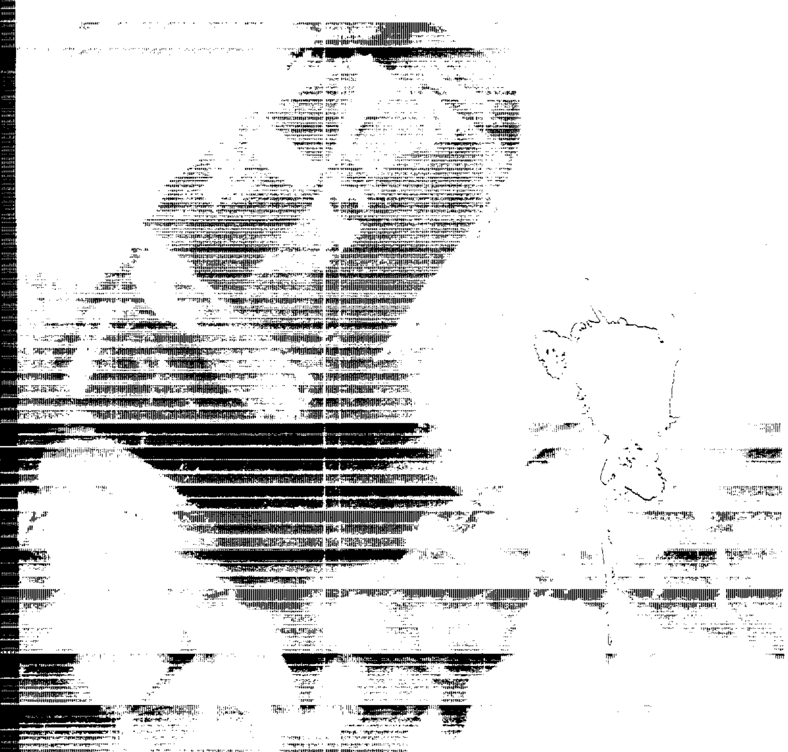
On behalf of the Board of Directors:

Donald J. Taylor
Chair of the Board of Directors
March 3, 2004

Patrick D. Daniel
President & Chief Executive Officer



Enbridge — A Profile



Enbridge is an experienced and knowledgeable asset manager with a reputation for steady growth and a low-risk profile. It is also a values-based organization with a commitment to corporate responsibility in all of its business activities.

March

[illegible], having [illegible] interest in the Alliance Pipeline from 21.4% at year-end 2001 to [illegible]% at [illegible] 2003, announced [illegible] acquiring additional interests in the pipeline. In 2003 the Company increased its interest in both the Canadian and U.S. segments of the pipeline to 50%. In June, Enbridge Inc. [illegible] its 50% interest in the Canadian segment of the Alliance Pipeline to the Enbridge Income Fund.

April

The Terrace Phase [illegible] expansion of Enbridge's crude oil mainline was officially completed and placed into [illegible]. Phase [illegible] increased delivery capacity by 140,000 barrels per day on the Enbridge and Lakehead Systems.

May

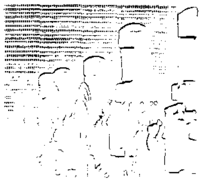
Enbridge announced the creation of Enbridge Income Fund. The Fund is a premier income fund in Canada [illegible] focused on pipeline transportation assets. The successful initial public offering closed on June [illegible] and the Fund began trading on the Toronto Stock Exchange under the trading symbol [illegible]. [illegible] the Fund acquired from Enbridge Inc. a 50% interest in the Canadian portion of the Alliance Pipeline and a 100% interest in Enbridge Pipelines (Saskatchewan) Inc. for gross proceeds of $[illegible] million. Enbridge Inc. owns a 72.3% overall interest in the Fund.

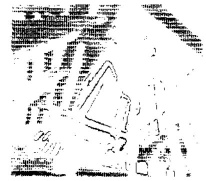
July

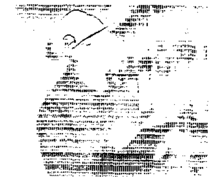
[illegible] Chicago Pipeline [illegible] new markets for Canadian crude oil [illegible]. The Company [illegible] interest in September for US$[illegible] million. Subject to [illegible] of proposed tolling arrangements by Canadian producers and regulatory approval, Enbridge [illegible] to transport Canadian crude oil south from Chicago to Cushing. The reversal [illegible] the Spearhead Pipeline.

September

[illegible]% interest in the Vector Pipeline [illegible] natural gas transmission pipeline with capacity of [illegible] billion cubic feet [illegible] gas from the Chicago area market hub in Illinois to the [illegible] County, Ontario.





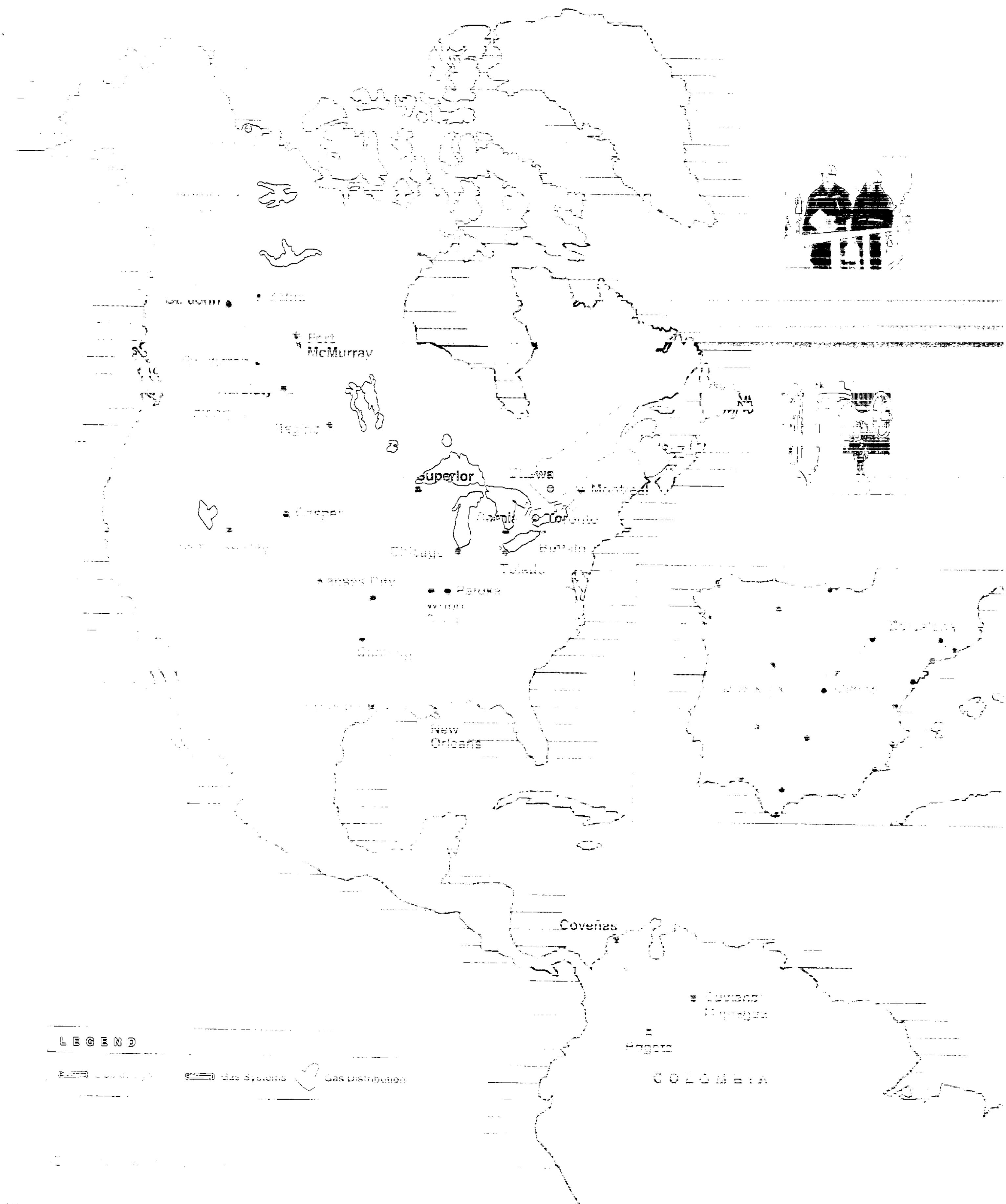


September [illegible]

October [illegible]

November [illegible]

December [illegible]

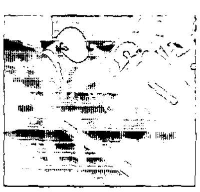

Fort McMurray
Casper
Superior
Montreal
Chicago
Buffalo
Toledo
Kansas City
Patoka
New Orleans
Coveñas
COLOMBIA
LEGEND
Gas Systems
Gas Distribution

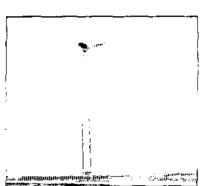
Enbridge's operations are focused on three energy delivery businesses: crude oil pipelines, natural gas pipelines, and natural gas distribution. The business of the Company is carried out by a variety of affiliates owned in whole or in part by Enbridge Inc.

Liquids Pipelines
- Enbridge Pipelines Inc. (100%)
- Enbridge Pipelines (NW) Inc. (100%)
- Enbridge Pipelines (Athabasca) Inc. (100%)
- Enbridge Pipelines (Toledo) Inc. (100%)
- Mustang Pipe Line Partners (30%)
- Chicap Pipe Line Company (22.8%)
- Frontier Pipeline Company (77.8%)
- Spearhead Pipeline (90%)

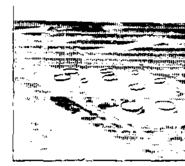
Gas Pipelines
- Alliance Pipeline L.P. (U.S. portion) (50%)
- Vector Pipeline Limited Partnership (60%)

Sponsored Investments
- Enbridge Energy Partners, L.P. (12.2%)
  - Lakehead System
  - Enbridge Pipelines (North Dakota) System
  - Midcontinent and Gulf Coast Systems
- Enbridge Income Fund (72.3% overall interest)
  - Enbridge Pipelines (Saskatchewan) Inc. (100%)
  - Alliance Pipeline Limited Partnership (Canadian portion) (50%)

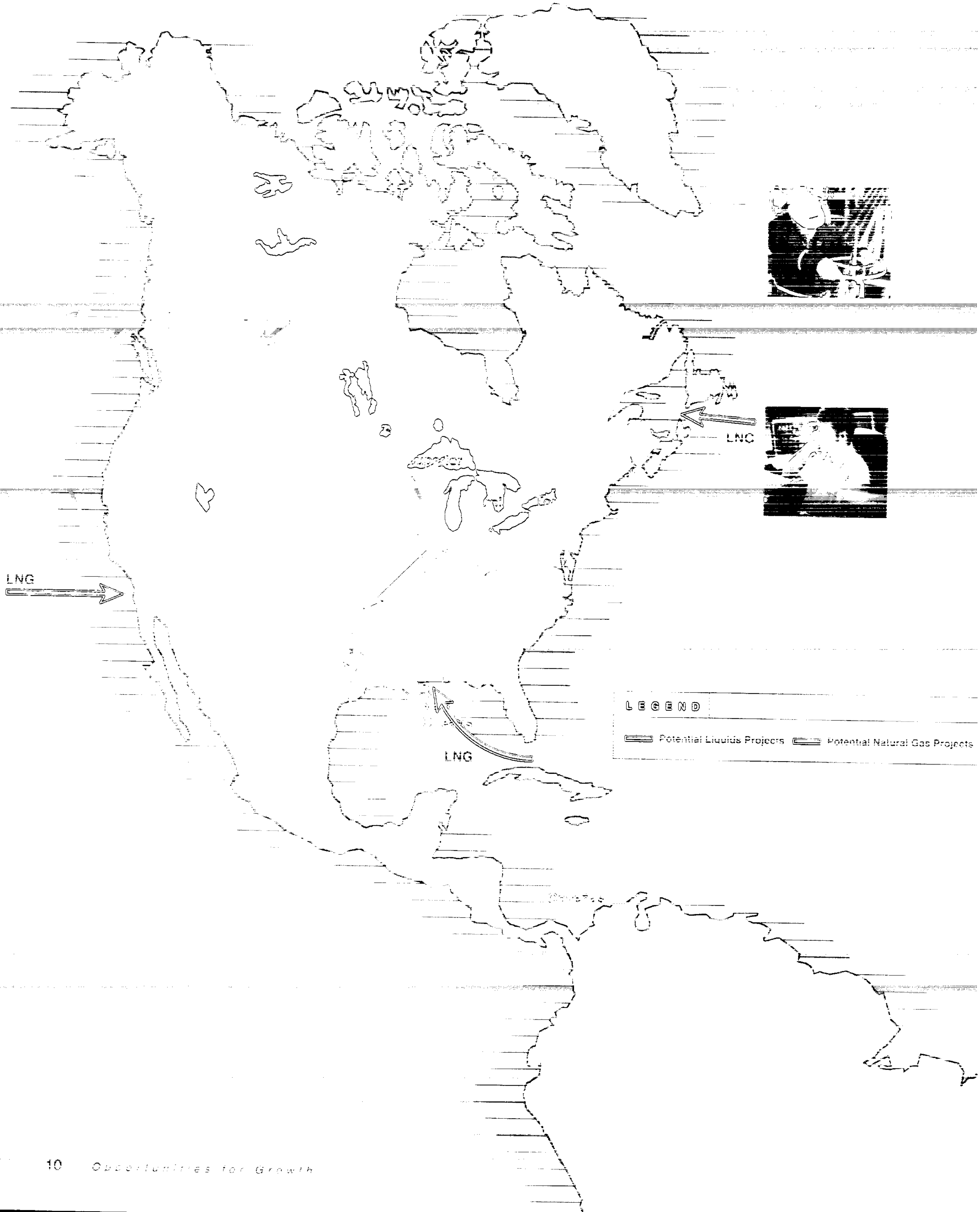




Gas Distribution and Services
- Enbridge Gas Distribution (100%)
  - Gazifere Inc.
  - Niagara Gas Transmission Limited
  - St. Lawrence Gas Company, Inc.
- Noverco Inc. (32.1%), which owns:
  - Gaz Métro Limited Partnership (74.7%), which owns:
    - Vermont Gas Systems, Inc. (100%)
    - TQM Pipeline and Company, Limited Partnership (50%)
    - Portland Natural Gas Transmission System (38.3%)
- Enbridge Gas New Brunswick Limited Partnership (63%)
- CustomerWorks Limited Partnership (70%)
- Enbridge Commercial Services (100%)
- AltaGas Services Inc. (40.3%)
- Aux Sable Liquids Products Inc. (42.7%)
- Enbridge Gas Services Inc. (100%)
- Inuvik Gas Ltd. (33 1/3%)
- Tidal Energy Marketing Inc. (100%)
- NetThruPut Inc. (52%)
- SunBridge Wind Power Project (50%)
- FuelCell Energy/Global Thermoelectric Inc. (strategic alliance)



International
- Oleoducto Central S.A. (24.7%)
- Compañia Logistica de Hidrocarburos CLH, S.A. (25%)
- Enbridge Technology Inc. (100%)


LNG
LNG
LNG
LEGEND
Potential Liquids Projects
Potential Natural Gas Projects

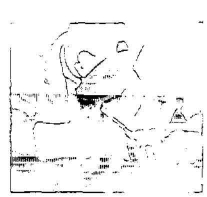
Accessing new markets to bring new supplies of crude oil and natural gas on stream is a crucial strategy for growth for Enbridge. The Company plans to do this by extending its continental reach.

As the primary transporter of Western Canadian crude oil, Enbridge is well positioned to develop additional infrastructure to deliver the growing volumes that are coming from Alberta's oil sands. With an estimated $50 billion in active or planned projects in the oil sands, new production is expected to come on stream steadily during the next 10 to 15 years, with an additional 800,000 barrels per day likely available by 2010.

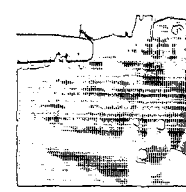
Enbridge has been working with its customers to develop market solutions that will enable crude oil shippers to have access to new markets in a timely, cost-effective manner. Our transportation development strategy is to provide Canadian producers with continued access to the premier markets Enbridge currently serves, and to gain access to southwestern and eastern PADD II markets, the Gulf Coast, California, and the Far East.

Key components of the Enbridge strategy include the following:

- Subject to acceptance of proposed tolling arrangements by Canadian producers and regulatory approvals, Enbridge plans to reverse the Cushing-to-Chicago Pipeline that it acquired in 2003 to flow from north to south. The pipeline will be renamed the Spearhead Pipeline and will transport Western Canadian production and incremental oil sands volumes to new markets in the Central and Midwestern U.S. The Company is also pursuing delivery options for Canadian crude extending beyond Cushing to U.S. Gulf Coast markets.



- Enbridge Energy Partners has proposed building a new crude oil pipeline to provide access from its existing terminal at Superior, Wisconsin, south to the Wood River hub in southern Illinois. This Southern Access Pipeline, to be part of the Lakehead System, will interconnect with the Spearhead Pipeline. In December 2003, EEP also announced plans to acquire the Ozark Pipeline that transports crude oil from Cushing to Wood River, and a number of complementary pipeline and terminal assets.



- Enbridge has proposed constructing a new crude oil pipeline from the Athabasca oil sands region to the B.C. coast, for tidewater access to California and Asia-Pacific markets.

The growing requirement to provide North American natural gas markets with new sources of supply is also presenting Enbridge with opportunities for growth.

In 2003 Enbridge increased its interests in the Alliance and Vector natural gas pipeline systems to 50% and 60%, respectively, strengthening its position in gas transmission. The Company is looking at opportunities to deliver gas production from the Wyoming area to U.S. Midwest markets, and to move gas volumes further east. It is pursuing opportunities to invest in Liquefied Natural Gas projects: increased imports of LNG are expected to become an important source of supply for North America, and Enbridge is interested in participating as a provider of regasification and take-away infrastructure. Enbridge also remains interested in northern gas and liquids development.

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

[illegible]

[illegible] Report on Business Corporate Governance/Best Boards [illegible] AAA+, which is the highest ranking possible.

Senior Management

Standing (left to right)

Stephen J.J. Letwin
Group Vice President, Gas Strategy & Corporate Development

J. Richard Bird
Group Vice President, Transportation North

Mel F. Belich
Group Vice President, International & Corporate Law

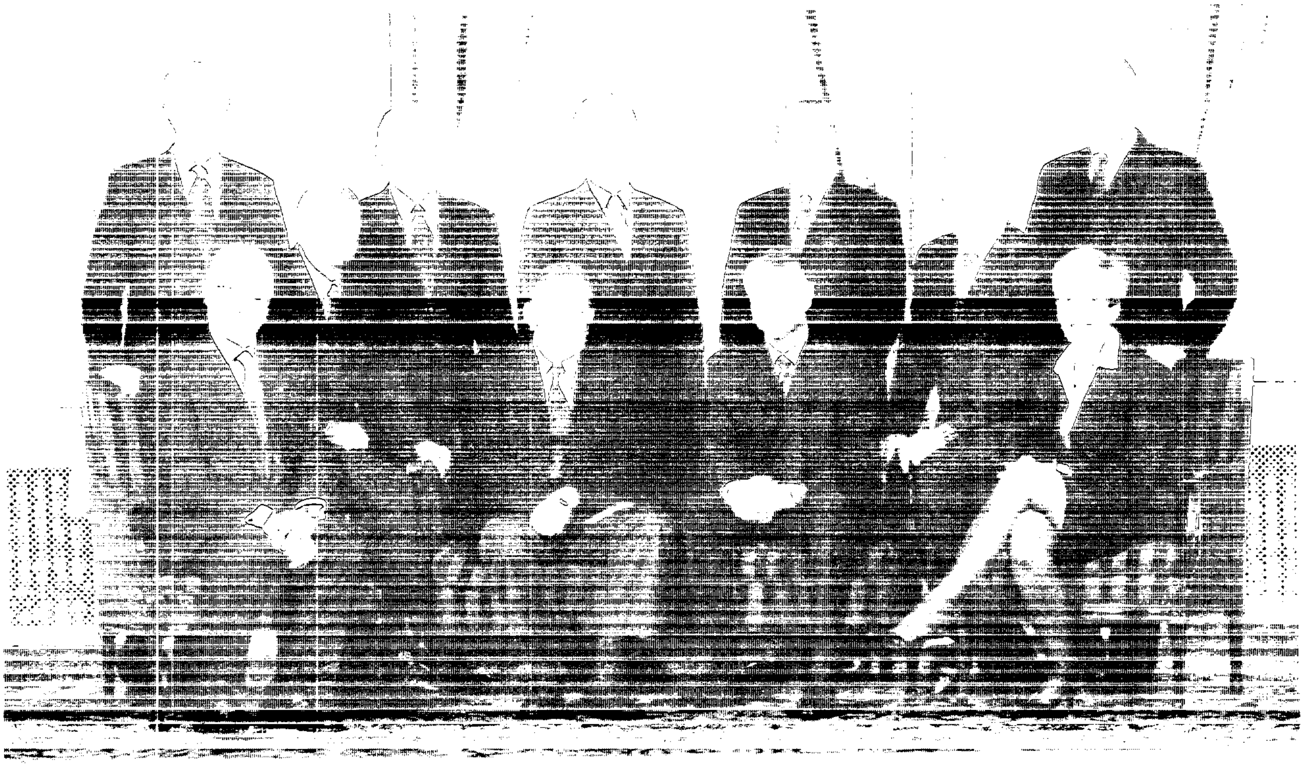
Dan C. Tutcher
Group Vice President, Transportation South

Bonnie D. DuPont
Group Vice President, Corporate Resources

Seated (left to right)

Patrick D. Daniel
President & Chief Executive Officer

Stephen J. Wuori
Group Vice President & Chief Financial Officer



Board of Directors

Standing (left to right)

Louis D. Hyndman, Edmonton, Alberta
Senior Partner, Field LLP

Robert W. Martin, [illegible]
Corporate Director

Richard L. George, Calgary, Alberta
President & Chief Executive Officer, Suncor Energy Inc.

James J. Blanchard, Beverly Hills, Michigan
Senior Partner, Piper Rudnick

George K. Petty, [illegible]
Corporate Director

Seated (left to right)

J. Lorne Braithwaite, Toronto, Ontario
Corporate Director

David A. Arledge, [illegible]
[illegible]

Donald J. Taylor, Jacksons Point, Ontario
Chair, Enbridge Inc.

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

William R. Lett, Toronto, Ontario
Chief Executive Officer, [illegible]

E. Susan Evans, Calgary, Alberta
Corporate Director

Enbridge has always considered the safety of employees and the public, a clean and healthy environment, and strong, vibrant communities to be priorities. That's why the adoption in December 2003 of a full corporate responsibility platform was a logical step for the Company.

Corporate responsibility defines how we will relate to others in terms of our performance in areas such as the environment, health, safety, governance, human rights, community investment and stakeholder engagement.

Enbridge had already taken many of the steps to move in that direction. At the same time, stakeholders key to our success were asking for a commitment to sustainable business practices in a visible and permanent way. A corporate responsibility platform will document the commitments we have already made and will make our sustainable approach replicable by helping us define and measure our performance.

The cornerstone of corporate responsibility is sustainability, and simply put, a sustainable enterprise is one that is built for the long-term. Business decisions combine economic realities with the social and environmental considerations that ensure longevity.

In 2003, Enbridge had a number of notable achievements in areas that fall under the corporate responsibility banner.

- Enbridge employees, senior management and Board of Directors are all guided by the Company's basic code of business conduct — the *Statement on Business Conduct*. Adherence to this code of conduct, which incorporates the internationally recognized *Voluntary Principles on Security and Human Rights*, is a condition of employment. In an effort to share Company experiences and 'lessons learned' in these fields, in 2003 Enbridge became a signatory to the *United Nations Global Compact*.

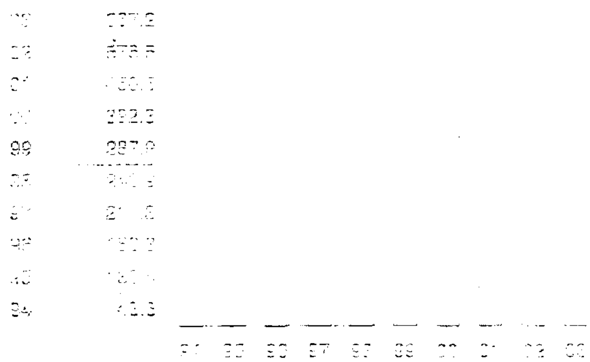
Where Energy Meets People

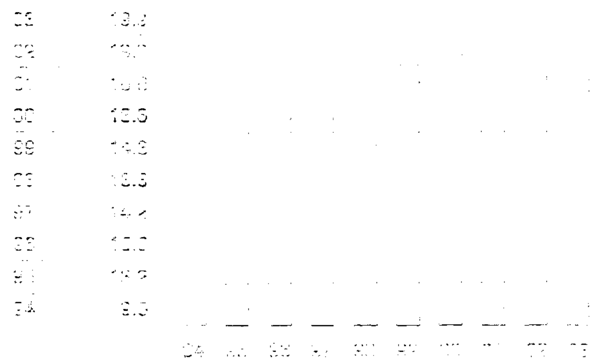
In 2003, Enbridge launched a corporate reputation campaign to advance the company's brand image and profile the valuable relationships we foster with stakeholder communities. The campaign profiles the leadership attributes of key community investment partners from the various regions where Enbridge operates.

This initiative, under the direction of UN Secretary-General Kofi Annan, brings companies together with UN agencies, labour organizations and civil society to support nine principles in the areas of human rights, labour and the environment.

- In 2003, Enbridge again invested $3 million in communities where the Company operates, primarily in health, the environment, arts and culture, social services, education, and civic leadership. And for the fifth consecutive year, Enbridge employees across Canada and the United States raised more than $1 million for United Way campaigns.
- In Colombia, where Enbridge operates and has a 24.7% investment in the OCENSA crude oil pipeline, OCENSA celebrated the first anniversary of its formalized human rights policy, which was developed and implemented using the *Voluntary Principles on Security and Human Rights* as a guideline. The policy commits OCENSA to respect human rights and obligates employees and contractors to reject violence and avoid associating with any of the illegal armed groups in Colombia. OCENSA conducted human rights training for 100% of its employees and its major contractors, and for nearly 1,000 military personnel stationed near the pipeline. OCENSA has also hired a designated Human Rights Coordinator who, along with the company's Auditor, has the authority to review and audit the conduct of all contractors and employees as their actions pertain to human rights and to ensure compliance with OCENSA's human rights policy.

Financial Review





CONSOLIDATED RESULTS

[illegible]	2003	[illegible]	[illegible]
[illegible]			
Liquids Pipelines	213.5	[illegible]	[illegible]
[illegible]	70.1	[illegible]	[illegible]
[illegible]	234.3	[illegible]	[illegible]
[illegible]	153.6	[illegible]	[illegible]
[illegible]	72.3	[illegible]	[illegible]
Corporate	(76.6)	[illegible]	[illegible]
Earnings from continuing operations	667.2	[illegible]	[illegible]
Discontinued operations	–	[illegible]	[illegible]
	667.2	[illegible]	[illegible]
Earnings Per Share			
Earnings — Continuing operations	4.03	2.09	2.63
Earnings — Discontinued operations	–	[illegible]	[illegible]
	4.03	[illegible]	[illegible]
[illegible]			
Earnings – Continuing operations	4.00	2.06	2.60
Earnings – Discontinued operations	–	[illegible]	[illegible]
	4.00	[illegible]	[illegible]
Total Assets	13,823.3	[illegible]	[illegible]
[illegible]	7,347.5	[illegible]	[illegible]
[illegible]	1.66	[illegible]	[illegible]
[illegible]	283.9	251.1	[illegible]

[illegible]

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

Significant factors and variances affecting consolidated earnings are as follows:

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

Enbridge made several strategic achievements during the year.

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

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

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

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

CORPORATE STRATEGY

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

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

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

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

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

LIQUIDS PIPELINES

Financial Results

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

Business Activities

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

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

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

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

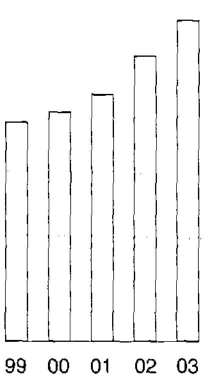
Feeder Pipelines and Other primarily includes a number of liquids pipelines in the United States (Frontier, Toledo, Mustang and Chicap), as well as business development costs related to Liquids Pipelines activities.

Results of Operations

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

Liquids Pipelines Earnings

(millions of dollars)



99	146.0
00	152.5
01	164.4
02	189.6
03	213.5

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

Enbridge System

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

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

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

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

Athabasca System

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

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

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

NW System

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

Saskatchewan System

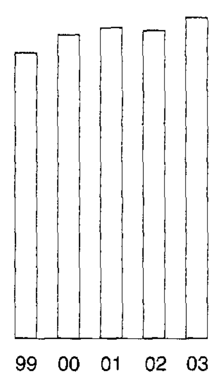
The earnings decrease noted in the Saskatchewan System of $3.3 million from 2002 is due to the Company's sale of this asset to EIF effective June 30, 2003.

Feeder Pipelines and Other

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

Deliveries[1]

(thousands of barrels per day)



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

1 Includes deliveries by the 12.2% owned Lakehead System

Outlook

Enbridge System

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

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

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

Enbridge Athabasca System

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

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

Supply

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

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

Capital Expenditures

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

Business Risks

Supply and Demand

The operation of the Company's liquids pipelines are dependent upon the supply of and demand for crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, is dependent upon a number of variables, including the availability and cost of capital for oil sands projects, the price of natural gas used for steam production, and the price of crude oil. Oil targeted drilling licenses in Western Canada increased 25% in 2003 from 2002. This strong drilling activity, along with the start-up of Shell's Athabasca oil sands project, resulted in significant production growth over 2002. For 2004, growth is expected to continue with full year production from Shell's Athabasca oil sands project and expansions at Cold Lake, and the completion of expansions at Syncrude and Suncor.

1 CAPP Statistical Handbook — current year

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

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

Regulation

Earnings from the Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from these operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity. To the extent the NEB rate of return fluctuates, a portion of the earnings of the Enbridge System changes. The Company believes that regulatory risk has been reduced through the negotiation of long-term agreements, such as the ITS, with its customers.

Competition

The Enbridge System transported approximately 67% of total Western Canadian crude oil production in 2003 and provides approximately 77% of the capacity for the transportation of Western Canadian crude oil out of Canada. Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, and proximity to markets. TransMountain Pipeline and Express Pipeline, as well as other common carriers, can be used by producers to ship Western Canadian crude oil to refineries in either Canada or the United States. Although the Company does not compete directly in the regions served by these other pipelines, producers can elect to have their crude oil refined elsewhere than delivery points on the Enbridge System. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls.

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

Environment and Safety

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of accidents and injuries, and protection of the environment benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety, and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. These systems reflect industry best practices and are aligned with the ISO 14001 standard and the BSI-OHSAS 18001 specification for environmental, health and safety management systems. Regular reviews and audits are conducted to assess compliance with legislation and company policy.

Pipeline leaks are an inherent risk of operations. The Company has an extensive program to manage system integrity, which includes the development and use of predictive and detective in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The company also maintains comprehensive insurance coverage for significant pipeline leaks.

GAS PIPELINES

Financial Results

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

Business Activities

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

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

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

Results of Operations

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

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

Alliance Pipeline (US)

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

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

Alliance Pipeline (Canada)

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

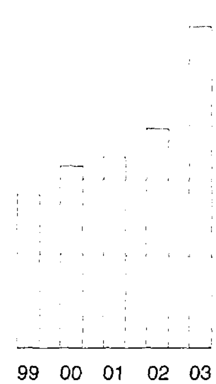
Vector Pipeline

The contribution from Vector is $3.1 million higher in 2003, compared with 2002, as a result of increased volumes and transportation margins, due to both colder than normal weather in Eastern Canada and higher storage injections. This is further enhanced by additional ownership interests of 15.0% acquired in the fourth quarter of 2003. The Company's current ownership is 60.0%.

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

Gas Pipelines Earnings

(millions of dollars)



99	33.2
00	39.6
01	41.5
02	47.8
03	70.1

Outlook

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

Supply and Demand for Natural Gas

North American natural gas demand is expected to grow at a modest rate for the next three to five years primarily driven by growth in power generation, which more than offsets declines in industrial demand. Demand growth is expected to be constrained by recent strong prices and increased volatility due to supply concerns from traditional sources. Over time, the entry of new supplies from the U.S. Rockies, Liquefied Natural Gas, and the Alaska North Slope/Mackenzie Delta are expected to alleviate supply concerns. This is expected to improve the stability of natural gas prices and provide a more favourable pricing structure that will facilitate further growth in the power generation market.

Business Risks

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

Exposure to Shippers

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

Pipeline Operating Risk

As with any comprehensive pipeline system, the operation of Alliance and Vector involves many risks, including: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to keep on hand adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the respective systems. The occurrence or continuance of any of these events could increase the cost of operating Alliance or Vector and reduce transportation capacity, thereby impacting earnings. Risks of substantial costs and liabilities, including those from leaks and explosions, are inherent in pipeline operations and there can be no assurance that significant costs and liabilities will not be incurred, including those relating to claims for damages to property and persons.

SPONSORED INVESTMENTS

Financial Results

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

Business Activities

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

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

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

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

Results of Operations

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

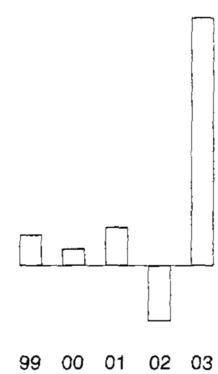
Excluding the impact of these gains, earnings in this segment increased $102.1 million from 2002. A significant portion of this year-over-year change is due to an $82.2 million writedown recorded in 2002 on the sale of the Midcoast assets. The remainder of the $19.9 million increase is attributed to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

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

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

Sponsored Investments Earnings

(millions of dollars)



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

Enbridge Energy Partners

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

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

Enbridge Midcoast Energy

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

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

Enbridge Income Fund

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

Outlook

Enbridge Energy Partners

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

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

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

Enbridge Income Fund

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

Business Risks

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

Enbridge Energy Partners

Supply and Demand

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

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

Certain of EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, natural gas liquids and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas.

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP are subject to regulation by FERC or state regulators. Gas gathering currently is not subject to active regulation. Several of EEP's assets are regulated by FERC and their revenues could decrease if tariff rates were protested.

Market Price Risk

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

Enbridge Income Fund

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

Supply and Demand

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

Competition

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

GAS DISTRIBUTION AND SERVICES

Financial Results

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

Business Activities

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

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

CustomerWorks/ECS includes the operations of CustomerWorks LP, whose operations commenced on January 1, 2002, and provides services covering the entire meter-to-cash process, including many of the services which, until then, were provided by Enbridge Commercial Services (ECS). The results of ECS in 2002 and 2001 also include information technology and fleet services, which were rebundled into EGD in the fourth quarter of 2002. CustomerWorks was formed by Enbridge and Terasen and serves over 3.5 million customers including those of Terasen's and Enbridge's gas distribution operations. In August 2002, CustomerWorks outsourced the provision of its customer care services to a new entity owned and operated by Accenture Inc.

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

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

Results of Operations

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

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

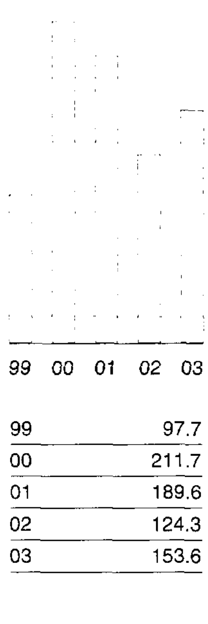
Enbridge Gas Distribution

Earnings from EGD increased by $17.7 million in 2003 from 2002. The increase was due to higher gas distribution margins caused by increased distribution volume resulting from colder weather. This is partially offset by a $26.0 million regulatory receivable writedown related to a prior year, a $7.1 million OEB gas cost disallowance related to long-term transportation contracts and a $4.6 million OEB outsourcing disallowance. Had EGD experienced normal weather in its franchise area, reported net earnings would have decreased by approximately $46.1 million after tax. Normal weather is the weather forecast by EGD, in the Toronto area, including the impacts of both the long run and short run actual historical weather experience, more heavily weighted on the short run experience. The effect of weather is measured by degree-day deficiency and is calculated by accumulating, from October 1, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. This financial measure is unique to EGD and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized factors that may be identified by other companies. Moreover, normal weather may not be comparable year-to-year given that the forecasting model uses the degree-days from the most recent years to determine the estimate. This weather-normalized adjustment is consistent with the manner in which EGD calculates degree-days for regulatory purposes.

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

Gas Distribution and Services Earnings

(millions of dollars)



99	97.7
00	211.7
01	189.6
02	124.3
03	153.6

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

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

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

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

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

CustomerWorks/ECS

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

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

Noverco

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

Variations from normal weather do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preference share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%. The weighted average dividend yield on the preference shares, which is reset annually, was approximately 10% for each of the last three years.

Enbridge Gas New Brunswick

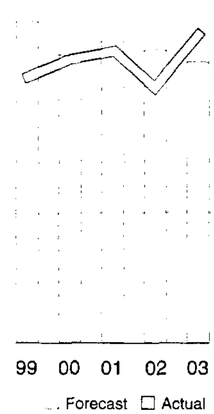
Earnings from Enbridge Gas New Brunswick improved in 2003 due to increased customer connections. Earnings were better in 2002 than 2001 due to a full year of operations.

Gas Services

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

Energy Distribution Degree Day Deficiency

(degrees Celsius)



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

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

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

Outlook

Enbridge Gas Distribution

2004 Rate Application

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

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

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

Review of OEB Formula for Setting ROE

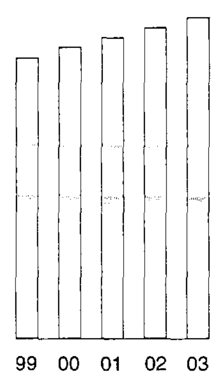
In September 2003, the OEB completed a hearing to review and consider possible revisions to the current ROE formula that is adjusted by any change in the long-term Canadian bond yield. EGD filed evidence to propose a ROE for 2004 of 11.2%. The increase in the requested ROE reflects EGD's belief that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

Legislative Change and Future Regulatory Direction

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

Energy Distribution Number of Active Customers

(thousands)



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

Gas Distribution Access Rule

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

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

Enbridge Gas New Brunswick

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

Capital Expenditures

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

Business Risks

Enbridge Gas Distribution

The business risks inherent in the natural gas distribution industry impact the ability of EGD to realize the revenue level required to generate the allowed return on equity. These business risks include timely and adequate rate relief, accuracy in forecasting distribution volume, and, most importantly, achieving the forecast natural gas distribution volume. The new Ontario government's intentions with respect to the current freeze in electricity prices, which expires in 2006, and the direction of natural gas prices in the medium to long term will impact EGD's competitiveness in the energy market.

Volume Risks

Since customers are billed on a volumetric basis, the ability to collect the total revenue requirement (the cost of providing service) depends upon achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather; economic conditions; pricing of competitive energy sources; and the number of customers.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 77% (2002 – 74%) of total distribution volume. Weather during the year, measured in degree-days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies along with more efficient building construction that continues to place downward pressure on annual average consumption. In addition, technology issues combined with increased costs of residential natural gas water heaters may pressure EGD's market share for natural gas water heaters.

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

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as mix of sales and transportation of gas for customers, the mix between the higher margin residential and commercial sectors, and lower margin industrial sector. The timing of gas sales is also a factor, as higher rates are charged during the winter season than during the summer season.

Rate Relief

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

Rate relief could also be sought for significant unforecasted amounts allowing EGD to recover the costs of providing and maintaining the quality of its service while achieving the allowed rate of return on rate base.

EGD does not profit from the sale of the natural gas commodity nor is it at risk for the difference between the actual cost of gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition. EGD monitors the balance and its potential impact on ratepayers and requests, on a quarterly basis, interim rate relief that will allow EGD to recover or refund the gas commodity cost differential.

Forecasting Accuracy

Forecasting accuracy is a risk since rate applications are made or rates are established in advance based on anticipated distribution volume by class of customer. Forecasts are also made for the future cost of capital including the forecast yield rate for long-term Government of Canada Bonds used in the determination of the return on equity. Consequently, the forecasting process ensures that any changes in cost of service, regardless of whether they are caused by inflation or by level of business activity, would be recovered in new rates approved for that fiscal year based on the anticipated distribution volume.

Gas Services

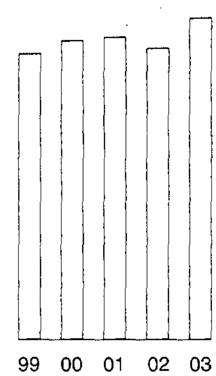
Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago and between Chicago and Dawn. To the extent that the difference in the price of natural gas in the various locations is not greater than the cost of transportation between Alberta and Chicago or Dawn, earnings will be negatively affected.

Aux Sable

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

Energy Distribution Volume of Gas Distributed

(billions of cubic feet)



99	402
00	421
01	427
02	410
03	458

INTERNATIONAL

Financial Results

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

Business Activities

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

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

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

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

Results of Operations

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

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

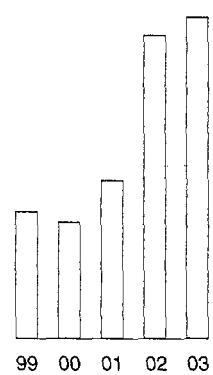
Outlook

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

Increased international asset rationalization, the changing corporate strategies of multinationals, and the privatization of energy transportation activities in focus regions should continue to present grassroots investment and acquisition opportunities. Opportunities will be evaluated against the Company's strict investment criteria. Latin America and Western Europe are key regions of interest. Enbridge plans for the International segment to contribute approximately 15% of the Company's earnings over the long term.

International Earnings

(millions of dollars)



99	28.7
00	26.4
01	35.6
02	68.0
03	72.3

Business Risks

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

CORPORATE

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

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

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

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

DISCONTINUED OPERATIONS

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

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

CRITICAL ACCOUNTING POLICIES

Rate Regulation

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

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

If the regulator's future actions are different from the Company's expectations, the timing and amount of the recovery of liabilities or refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

LIQUIDITY AND CAPITAL RESOURCES

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

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

Operating Activities

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

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

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

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

Investing Activities

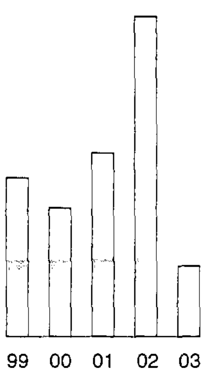
Cash provided from investing activities for the year ended December 31, 2003 was $259.5 million compared with cash used in investing activities of $251.7 million in 2002 and $1,621.7 million in 2001. Investing activities in 2003 represented a source of cash primarily as a result of the proceeds received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

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

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

Capital Expenditures, Investments and Acquisitions

(millions of dollars)



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

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

Financing Activities

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

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

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

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

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt	4,693.1	450.0	968.6	589.3	2,685.2
Non-recourse long-term debt	725.4	32.5	84.4	72.0	536.5
Non-recourse capital leases	61.2	1.7	3.6	3.6	52.3

RISK MANAGEMENT

Operating Risk

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

Market Risk

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

Foreign Exchange Risk

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

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on variable rate debt and floating to fixed swaps are used to manage this exposure. The Company monitors its levels of fixed and variable rate debt instruments and, from time to time, fixed to floating swaps are used to help maintain balances of each commensurate with the Company's financing strategies. The Company also enters into interest rate derivatives to hedge a portion of the interest cost of future debt issues related to specific capital projects.

Commodity Price Risk

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

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

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

Natural Gas Supply Management

Customers of EGD are exposed to changes in the price of the natural gas commodity. A portion of the future natural gas supply requirements is hedged using natural gas swaps and options that manage the price of natural gas, as allowed by the OEB. Since the cost of the natural gas commodity is paid by customers, this risk mitigation strategy is for the account of the customers. The OEB monitors the policies, procedures and results of this hedging program.

Derivative Financial Instruments Used for Risk Management

(millions of dollars unless otherwise noted)

December 31,	2003			2002		
	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	535.8	(30.6)	2005-2022	535.8	24.9	2005-2022
Euro cross currency swaps	434.7	(46.1)	2004-2019	371.1	(54.4)	2003
Forwards *(cumulative exchange amounts)*	1,889.5	67.9	2004-2022	1,993.0	(244.6)	2003-2022
Energy commodities						
Natural gas *(bcf)*	63.6	12.4	2004-2008	35.3	(1.5)	2003-2004
Natural gas supply management *(bcf)*	13.1	(3.4)	2004	5.9	(0.2)	2003
Interest rates						
Interest rate swaps	561.0	1.9	2005-2029	934.1	0.6	2003-2029
Forward interest rate swaps	532.0	(1.0)	2004-2005	–	–	–

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset an exposure related to income taxes on foreign currency gains or losses on Canadian dollar debt of a U.S. subsidiary. These instruments are recorded at fair value and have a fair value payable of $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

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

Fair Values of Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties, calculated at the reporting date, to settle these instruments. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The estimated fair values of all other financial instruments are based on quoted market prices or, in the absence of specific market prices, on quoted market prices for similar instruments and other valuation techniques.

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

Total Debt

(millions of dollars)

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

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

QUARTERLY FINANCIAL INFORMATION[1]

(millions of Canadian dollars, except for per share amounts)

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

(millions of Canadian dollars, except for per share amounts)

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

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

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

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

FOURTH QUARTER 2003 HIGHLIGHTS

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

SUPPLEMENTARY INFORMATION

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

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

Related Party Transactions

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

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

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

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

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

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

The Company also provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable; where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates. Prices are determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

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

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

Dated February 24, 2004

When used in this document, the words "anticipate", "expect", "project", "believe", "estimate", "forecast" and similar expressions are intended to identify forward-looking statements, which include statements relating to pending and proposed projects. Such statements are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, weather and economic conditions and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers.

To the Shareholders of Enbridge Inc.

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

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

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

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

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

Stephen J. Wuori
Group Vice President & Chief Financial Officer

To the Shareholders of Enbridge Inc.

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

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

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

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada — Chartered Accountants
January 23, 2004

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

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

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada — Chartered Accountants
January 23, 2004

(millions of Canadian dollars, except per share amounts)

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

Consolidated Statements Of Retained Earnings

(millions of Canadian dollars, except per share amounts)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

Approved by the Board:

Donald J. Taylor
Chair

Robert W. Martin
Director

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

Liquids Pipelines

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

Gas Pipelines

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

Sponsored Investments

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM), (collectively, the Partnership) and Enbridge Income Fund (EIF). The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. From May 2001 to October 2002, the Company, through its subsidiary, Enbridge Pipelines Inc., owned 100% of Enbridge Midcoast Energy Inc., which is now a wholly owned subsidiary of EEP. Enbridge Income Fund is a publicly traded income fund whose primary operations include a 50% interest in a gas transmission pipeline and a 100% interest in a crude oil and liquids pipeline and gathering system.

Gas Distribution and Services

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, as well as gas service operations, including the Company's proportionately consolidated investment in Aux Sable and natural gas gathering and processing operations through an equity investment in AltaGas Services Inc.

International

The Company's International business invests in energy transportation and related energy projects outside of Canada and the United States. This business also provides consulting and training services related to proprietary pipeline operating technologies and natural gas distribution.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

Basis of Presentation

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for at cost.

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

Regulation

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

Revenue Recognition

Revenues are recorded when products have been delivered or services have been performed. Certain of the Liquids Pipelines, Gas Pipelines, and gas distribution operations within the Gas Distribution and Services segment are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts. For rate-regulated operations, revenue is recognized in a manner that is consistent with the underlying rate design as mandated by the regulatory authority. Certain other operations recognize revenue under the terms of enforceable, committed long-term delivery contracts.

Income Taxes

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

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

Foreign Currency Translation

The functional currency of the Company's foreign operations, except for certain financing and investing operations, is the U.S. dollar. The Company also holds a Euro dollar equity investment in a foreign operation in Spain. These operations, which include those of proportionately consolidated U.S. dollar investments and the Euro dollar equity investment, are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using average rates for the period. Gains and losses arising on translation of these operations are included as a separate component of shareholders' equity.

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

Cash

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

Gas in Storage

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

Property, Plant and Equipment

Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Interest during the construction period is capitalized. Regulated operations capitalize an allowance for interest during construction and, if approved, an allowance for equity funds used during construction, at rates authorized by the regulatory authorities.

Depreciation

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

Future Removal and Site Restoration Costs

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

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

Deferred Amounts

The Company defers certain charges which the regulatory authorities permit to be recovered through future rates. These charges are recognized when regulatory approval for these recoveries has been received. Other deferred charges are amortized straight-line over various periods depending on the nature of the charges and include long-term financing and hedging costs which are amortized over the terms of the related debt or hedge agreements.

Goodwill

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

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

Derivative Financial Instruments

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

The Company applies settlement accounting to derivative financial instruments. Under this method, gains and losses on derivative instruments that qualify for hedge accounting are not recorded until they are realized. The notional amounts are not recorded in the financial statements as they do not represent amounts exchanged by the counterparties.

Post-Employment Benefits

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

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years employees render service, except for the regulated operations of the Gas Distribution and Services segment where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

Stock-Based Compensation

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

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

Comparative Amounts

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

New Accounting Standards

Impairment of Long-lived Assets

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

Hedging Relationships

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

Generally Accepted Accounting Principles

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

Asset Retirement Obligations

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

Consolidation of Variable Interest Entities

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

2. SEGMENTED INFORMATION

Year ended December 31, 2003

	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution & Services	International	Corporate[1]	Consolidated
Revenues	821.5	222.1	–	3,785.4	26.2	0.1	4,855.3
Gas costs	–	–	–	(2,720.1)	–	–	(2,720.1)
Operating and administrative	(288.8)	(41.2)	–	(415.9)	(30.5)	(24.4)	(800.8)
Depreciation	(142.6)	(56.7)	–	(237.6)	(2.0)	(4.1)	(443.0)
Operating income/(loss)	390.1	124.2	–	411.8	(6.3)	(28.4)	891.4
Investment and other income/(expense)	3.4	36.6	113.1	19.8	78.1	(42.8)	208.2
Gain on sale of assets	–	–	239.9	–	–	–	239.9
Interest and preferred equity charges	(102.1)	(58.7)	–	(162.2)	(0.5)	(161.4)	(484.9)
Income taxes	(77.9)	(32.0)	(118.7)	(115.8)	1.0	156.0	(187.4)
Earnings/(loss) applicable to common shareholders	213.5	70.1	234.3	153.6	72.3	(76.6)	667.2

Year ended December 31, 2002

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

Year ended December 31, 2001

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

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

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

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

Total Assets

(millions of dollars)

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

Additions to Property, Plant and Equipment

(millions of dollars)

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

2. SEGMENTED INFORMATION *(continued)*

Geographic Information

Revenues [1]

(millions of dollars)

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

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

Property, Plant and Equipment

(millions of dollars)

December 31,	2003	2002
Canada	6,747.3	6,733.6
United States	1,776.6	204.8
Other	7.0	9.2
	8,530.9	6,947.6

3. DISPOSITIONS

Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) Inc.

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, the Company sold its 50% interest in the Canadian segment of the Alliance Pipeline together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. to EIF for total proceeds of $905.0 million before working capital adjustments of $20.6 million and transaction costs of $0.2 million. The Company recorded an after-tax gain on the sale of $169.1 million. Enbridge's net investment in Alliance Canada was $333.6 million at December 31, 2002 and was classified as a long-term investment. The net assets of Enbridge Pipelines (Saskatchewan) Inc. consist primarily of property, plant and equipment and comprised $86.5 million of Enbridge Inc.'s total property, plant and equipment balance at December 31, 2002.

Enbridge Midcoast Energy

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

4. ACQUISITIONS

Cushing to Chicago Pipeline System

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

Northeast Texas

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

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

Midcoast Energy Resources, Inc.

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

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

Frontier Pipeline Company

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

5. DISCONTINUED OPERATIONS

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

Selected financial information related to discontinued operations is as follows.

Earnings

(millions of dollars)

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

Selected Earnings Information

(millions of dollars)

Year ended December 31,	2002	2001
Revenues	181.9	463.0
Income tax expense	34.6	2.5
Allocated interest expense	12.1	35.4

6. PROPERTY, PLANT AND EQUIPMENT

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

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

7. JOINT VENTURE

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

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

7. JOINT VENTURE *(continued)*

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

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

8. LONG-TERM INVESTMENTS

(millions of dollars)

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

Equity investments include $536.4 million (2002 – $551.9 million) representing the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the date of purchase. The excess has been allocated to property, plant and equipment on the basis of estimated fair values and is amortized over the economic life of the assets.

Alliance Pipeline, Aux Sable and Vector Pipeline

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

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

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

The Partnership

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

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

Noverco

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

The Company owns a cost investment in Noverco of $181.4 million (2002 – $181.4 million), which is entitled to a cumulative dividend based on the average yield of Government of Canada bonds maturing in more than 10 years plus 4.34%.

CLH

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

8. LONG-TERM INVESTMENTS *(continued)*

Enbridge Income Fund

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

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

The Company's 38 million preferred units are accounted for as a $380.2 million cost investment at December 31, 2003. At the request of the Company, the ECT preferred units will be repurchased for cancellation in certain specified circumstances by ECT with a repurchase price per ECT preferred unit based on the net issue price realized from the sale (or that could be realized from the sale) of an ordinary trust unit to the public. The ECT preferred units have no voting rights and mature on June 30, 2033 at which time ECT is obligated to redeem all of the outstanding ECT preferred units for a price of ten dollars per unit. The economic terms of these units are comparable to those of ordinary common units. As such, the approximate fair value of these preferred units, valued at the December 31, 2003 closing price of $12.89 per ordinary common unit, is $490.1 million.

OCENSA Pipeline

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

Income from Equity Investments

(millions of dollars)

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

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

9. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars)

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

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

10. DEBT

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

1 Primarily commercial paper borrowings.
2 The principal amount is recorded at the swapped rate.
3 2002 included US$160.0 million.
4 Primarily commercial paper borrowings. Includes US$306.0 million (2002 – US$582.5 million).

Short-term debt in the amount of $1,000.0 million (2002 – $1,000.0 million) is supported by the availability of long-term committed credit facilities and has been classified as long-term debt.

Long-term debt maturities for the years ending December 31, 2004 through 2008 are $450.0 million, $528.6 million, $440.0 million, $369.3 million and $220.0 million, respectively.

Interest Rate Management

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

1 Subject to a cross-currency swap.

10. DEBT *(continued)*

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

Interest Expense

(millions of dollars)

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

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

Credit Facilities

(millions of dollars)

December 31, 2003	Committed	Uncommitted	Drawdowns
Liquids Pipelines	150.0	–	–
Gas Distribution and Services	659.0	6.5	14.5
Corporate	1,887.7	–	–
	2,696.7	6.5	14.5

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

11. NON-RECOURSE DEBT OF JOINT VENTURES

(millions of dollars)

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

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

The Senior Notes may be redeemed by Alliance Pipeline U.S. at any time, at a price equal to the outstanding principal plus accrued but unpaid interest and a make-whole premium. Alliance Pipeline U.S. may be required to redeem the Senior Notes, in whole or in part, from proceeds received under insurance claims for damages if the proceeds are not applied to repair or rebuild the Alliance pipeline system.

Interest on the Senior Notes is payable semi-annually. Principal repayments commenced June 30, 2001 on the 6.996% Senior Notes, December 31, 2001 on the 7.770% Senior Notes, June 30, 2003 on the 4.591% Senior Notes and commences June 30, 2019 on the 7.877% Senior Notes. Principal repayments are due semi-annually thereafter in each instance and are closely tied to the recovery rates for capital depreciation and deferred income taxes contained in the transportation agreements.

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

12. PREFERRED SECURITIES

The Company has $175.0 million of 7.6%, $200 million of 7.8%, and $175.0 million of 8.0% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after the fifth anniversary of each issue and have no stated maturity date. The Company has the right to defer, subject to certain conditions, payments of distributions on the securities for up to 20 consecutive quarterly periods. Deferred and regular distribution amounts are payable in cash or, at the option of the Company, in common shares of the Company. As a result, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $532.4 million at December 31, 2003 (2002 – $533.7 million).

13. SHARE CAPITAL

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

Common Shares

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

December 31,	2003		2002		2001	
	Number of Shares	**Amount**	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**169.7**	**2,169.0**	162.9	1,875.9	161.8	1,852.6
Dividend Reinvestment and Share Purchase Plan	**0.4**	**17.1**	0.2	8.3	0.2	7.2
Stock based compensation expense	**–**	**1.9**	–	–	–	–
Issued to Noverco	**–**	**–**	0.5	23.1	–	–
Public issue	**–**	**–**	5.0	225.4	–	–
Exercise of stock options and other	**1.8**	**51.9**	1.1	36.3	0.9	16.1
Balance at end of year	**171.9**	**2,239.9**	169.7	2,169.0	162.9	1,875.9

Preferred Shares

The 5,000,000 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, preferential dividends of $1.375 per share per year, payable quarterly. Subsequent to December 31, 2003, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $26.00 per share if redeemed on or prior to December 1, 2004; $25.75 if redeemed on or prior to December 1, 2005; $25.50 if redeemed on or prior to December 1, 2006; $25.25 if redeemed on or prior to December 1, 2007; and $25.00 if redeemed thereafter, in each case with all accrued and unpaid dividends to the redemption date.

13. SHARE CAPITAL *(continued)*

Earnings Per Common Share

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 5.3 million shares (2002 – 5.3 million shares), resulting from the investment in Noverco.

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

(number of common shares in millions)

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

Dividend Reinvestment and Share Purchase Plan

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

Shareholder Rights Plan

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

14. STOCK OPTION PLAN

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

Fixed Stock Options

Full-time, key employees are granted options to purchase common shares that are exercisable at the market price of common shares at the date the options are granted. Generally, options vest in equal annual installments over a four-year period and expire ten years after the issue date. Outstanding stock options expire over a period ending no later than February 6, 2013.

Outstanding Fixed Stock Options

(options in thousands; exercise price in dollars)

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

Fixed Stock Option Characteristics

(options in thousands; exercise price in dollars)

December 31, 2003

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

Performance-based Options

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

Outstanding Performance-based Options

(options in thousands; exercise price in dollars)

December 31,	2003		2002		2001	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**2,045**	**37.73**	1,479	32.03	1,480	31.60
Options granted	**–**	**–**	810	46.30	65	41.13
Options exercised	**(549)**	**31.39**	(244)	31.66	–	–
Options cancelled	**–**	**–**	–	–	(66)	31.35
Options at end of year	**1,496**	**40.05**	2,045	37.73	1,479	32.03
Options vested	**686**	**32.67**	1,235	32.10	740	31.31

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

14. STOCK OPTION PLAN *(continued)*

Pro forma Compensation Expense

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

(millions of dollars)

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

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

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

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

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

15. FINANCIAL INSTRUMENTS

Derivative Financial Instruments Used for Risk Management

The Company is exposed to movements in foreign currency exchange rates, interest rates and the price of energy commodities, primarily natural gas. In order to manage these exposures for both shareholders and ratepayers, the Company utilizes derivative financial instruments to create offsetting positions to specific exposures. These instruments are not used for speculative purposes.

Derivative financial instruments involve credit and market risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company minimizes credit risk by entering into risk management transactions only with institutions that possess investment grade credit ratings or with approved forms of collateral. For transactions with terms greater than five years, the Company may also retain the right to require a counterparty, that would otherwise meet the Company's credit criteria, to provide collateral.

Foreign Exchange

The Company has an exposure to foreign currency exchange rates, primarily because of its U.S. dollar denominated investments and its Euro investment in CLH where both carrying values and earnings are subject to foreign exchange risk. The Company utilizes par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure. In addition, cross currency swaps have been entered into to hedge the Company's exposure on its U.S. dollar denominated senior term notes.

Interest Costs

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

Energy Commodity Costs

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

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

Natural Gas Supply Management

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

15. FINANCIAL INSTRUMENTS *(continued)*

Fair Values

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

(millions of dollars unless otherwise noted)

December 31,	2003			2002		
	Notional Principal or Quantity	**Fair Value Receivable/ (Payable)**	**Maturity**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**535.8**	**(30.6)**	**2005-2022**	535.8	24.9	2005-2022
Euro cross currency swaps	**434.7**	**(46.1)**	**2004-2019**	371.1	(54.4)	2003
Forwards *(cumulative exchange amounts)*	**1,889.5**	**67.9**	**2004-2022**	1,993.0	(244.6)	2003-2022
Energy commodities						
Natural gas *(bcf)*	**63.6**	**12.4**	**2004-2008**	35.3	(1.5)	2003-2004
Natural gas supply management *(bcf)*	**13.1**	**(3.4)**	**2004**	5.9	(0.2)	2003
Interest rates						
Interest rate swaps	**561.0**	**1.9**	**2005-2029**	934.1	0.6	2003-2029
Forward interest rate swaps	**532.0**	**(1.0)**	**2004-2005**	–	–	–

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset an exposure related to income taxes on foreign currency gains or losses on Canadian dollar debt of a U.S. subsidiary. These instruments are recorded at fair value and have a fair value payable of $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

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

Fair Values of Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties, calculated at the reporting date, to settle these instruments. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The estimated fair values of all other financial instruments are based on quoted market prices or, in the absence of specific market prices, on quoted market prices for similar instruments and other valuation techniques.

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

Total Debt

(millions of dollars)

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

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

Trade Credit Risk

Trade receivables related to Liquids Pipelines consist primarily of amounts due from companies operating in the oil and gas industry and are collateralized by the crude oil and other products contained in the Company's pipelines and storage facilities. Credit risk in the Gas Distribution and Services segment is reduced by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. Included in accounts receivable is an allowance for doubtful accounts of $35.1 million at December 31, 2003 (2002 – $31.1 million).

16. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars)

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

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

16. INCOME TAXES *(continued)*

Components of Future Income Taxes

(millions of dollars)

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

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

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

Geographic Components of Pretax Earnings and Income Taxes

(millions of dollars)

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

17. POST-EMPLOYMENT BENEFITS

Pension Plans

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

Defined Benefit Plans

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

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

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

Defined Contribution Plans

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

Post-employment Benefits Other than Pensions

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

17. POST-EMPLOYMENT BENEFITS *(continued)*

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

(millions of dollars)

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

Major Categories of Plan Assets

(millions of dollars)

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

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

Rate of Return on Plan Assets

(millions of dollars)

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

The Pension Funds exist to ensure that pension benefits will be paid. The Company manages the investment risk of its Pension Funds by setting a long term, asset mix policy for each Pension Fund after consideration of: (i) the nature of Pension Plan liabilities; (ii) the investment horizon of the Plan; (iii) the going concern and solvency funded status and cash flow requirements of the Plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The above table reflects both the target allocation percentage for each of the categories presented at the end of the period, as well as, the expected long-term rate of return on assets, both on a weighted-average basis. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Plan Contributions by the Company

(millions of dollars)

Year ended December 31,	2003	2002	2003	2002
	OPEB		Pension Benefit	
Minimum contributions required	–	–	–	–
Additional contributions	11.2	8.5	11.2	19.7
Total contributions	11.2	8.5	11.2	19.7
Contributions expected to be paid in 2004	10.6		14.8	

17. POST-EMPLOYMENT BENEFITS *(continued)*

Net Pension Plan and OPEB Costs Incurred

(millions of dollars)

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

Net Pension Plan and OPEB Costs Recognized

(millions of dollars)

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

The above tables reflect the funded status, recorded pension and OPEB assets and liabilities and pension and OPEB cost for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a pay-as-you-go basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Gas Distribution and Services plans and the accrual method for other plans, the Company's pension cost was $9.4 million (2002 – $3.6 million credit; 2001 – $4.0 million cost). The pension asset was $71.4 million (2002 – $73.1 million). The Company's OPEB cost totaled $7.0 million (2002 – $6.8 million; 2001 – $5.9 million). The OPEB liability was $10.0 million (2002 – $8.4 million). These net benefits or liabilities are recorded on the balance sheet in Deferred Amounts and Other Assets. The pension and OPEB assets and obligations for discontinued operations were included in the sale transaction.

Economic Assumptions

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

Year ended December 31,	2003	2002	2001	2003	2002	2001
		OPEB			Pension Benefit	
Discount rate	6.79%	6.95%	7.15%	6.75%	6.81%	7.06%
Average rate of salary increases				4.00%	4.00%	4.00%
Average rate of return on pension plan assets	4.50%	4.50%	4.50%	7.25%	7.79%	7.79%

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

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

Medical Cost Trend Rates

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	4.5%	2011
Other Medical	4.5%	4.5%	2004
Enbridge U.S.	14%	5.5%	2011

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

18. INVESTMENT AND OTHER INCOME

(millions of dollars)

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

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of dollars)

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

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

20. RELATED PARTY TRANSACTIONS

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

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

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

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

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

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

The Company also provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable; where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates. Prices are determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

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

21. COMMITMENTS AND CONTINGENCIES

Enbridge Gas Distribution Inc.

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

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

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners have commenced an action, which they will be applying for certification as a class action, against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. Since the outcome is indeterminable, the Company has made no provision for any potential liability.

Enbridge Energy Partners

Enbridge Energy Company, Inc. (EEC), which holds a portion of the Company's equity interest in EEP, has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance, or to any liabilities relating to a change in laws after December 27, 1991. In addition, in the event of default, EEC, as the General Partner, is subject to recourse with respect to a portion of EEP's long-term debt, which amounts to US$248 million at December 31, 2003.

22. UNITED STATES ACCOUNTING PRINCIPLES

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

Earnings and Comprehensive Income

(millions of dollars except per share amounts)

Year ended December 31,	2003	2002	2001
Earnings under Canadian GAAP	700.8	610.1	482.9
Preferred security distributions [1]	(26.7)	(26.7)	(17.5)
Stock-based compensation [2]	–	(12.1)	(15.2)
Loss on ineffective hedges [5]	(53.8)	–	–
Change in income due to consolidation of EIF [7]	(2.3)	–	–
Change in gain due to consolidation of EIF [7]	(173.0)	–	–
Tax effect of the above adjustments	51.5	4.9	6.1
Future income tax recovery/(expense) [3]	–	–	92.8
Earnings under U.S. GAAP	496.5	576.2	549.1
Unrealized net gain/(loss) on cash flow hedges [6]	66.9	19.5	(150.8)
Reclassification adjustment on cash flow hedges [6]	80.6	–	–
Foreign currency translation adjustment [6]	(159.6)	(1.3)	15.1
Comprehensive income	484.4	594.4	413.4
Earnings per common share	3.00	3.55	3.45
Diluted earnings per common share	2.98	3.51	3.41

Financial Position

(millions of dollars)

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

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

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

Prior to the adoption of FAS 123, the Company accounted for stock-based compensation for U.S. GAAP in accordance with APB 25, Accounting for Stock Issued to Employees, which required the use of the intrinsic value-based method to measure compensation expense. Under Canadian GAAP, the Company's performance-based options did not give rise to compensation expense. Under U.S. GAAP, the Company's performance-based options, which vested during 2002 and 2001, gave rise to pre-tax compensation expense of $12.1 million and $6.9 million respectively. No performance-based options vested in 2003. In addition, under U.S. GAAP in 2001, the Company's Stock Appreciation Rights (SARs) were accounted for using the intrinsic value method, which resulted in pre-tax compensation expense of $8.3 million, whereas, under Canadian GAAP, SARs did not give rise to compensation expense.

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

Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. The additional deferred income taxes under U.S. GAAP include the difference between capital cost allowance and depreciation of property, plant and equipment of $551.2 million (2002 – $549.3 million) and the incremental revenue required for the recovery of unrecorded taxes of $286.6 million (2002 – $316.0 million).

4 *Accounting for Joint Ventures*
U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for joint ventures need not be reconciled from Canadian to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity. See Note 7 for summarized financial information of joint ventures.

5 Financial Instruments

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

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

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

6 Accumulated Other Comprehensive Loss

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

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

7 Consolidation of Variable Interest Entities

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

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

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

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

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

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

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

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

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

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

On June 30, 2003, the Company formed Enbridge Income Fund (EIF), a publicly traded entity with assets purchased from the Company. The Company has a 41.9% equity interest in EIF, as well as a preferred unit investment that has no voting rights, a stated par value and a 30-year maturity. The preferred units earn a return that is equivalent to the cash distributions per unit to the equity unit holders and are classified as a liability in EIF's financial statements.

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

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

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

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

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

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

Supplemental Disclosure — Pro Forma Compensation Expense

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

(millions of dollars except per share amounts)

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

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

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

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

Quarterly Share Trading Information

The Toronto Stock Exchange

2003 *(dollars)*	**First**	**Second**	**Third**	**Fourth**
High	**44.33**	**49.30**	**52.00**	**54.14**
Low	**40.95**	**42.71**	**47.50**	**47.90**
Close	**43.94**	**47.93**	**51.05**	**53.70**
Volume *(millions)*	**19.0**	**17.6**	**20.4**	**18.1**

2002 *(dollars)*	First	Second	Third	Fourth
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

The New York Stock Exchange

2003 *(U.S. dollars)*	**First**	**Second**	**Third**	**Fourth**
High	**30.02**	**36.76**	**37.75**	**41.66**
Low	**26.90**	**29.45**	**34.80**	**35.61**
Close	**29.80**	**35.62**	**35.63**	**41.39**
Volume *(millions)*	**1.3**	**0.9**	**0.6**	**0.5**

2002 *(U.S. dollars)*	First	Second	Third	Fourth
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

Corporate Responsibility and Environment, Health and Safety

Prevention of accidents and injuries, and protection of the environment benefits everyone. That's why environmental, health and safety performance is an integral part of Enbridge's businesses, and objectives and performance targets are established, implemented and monitored. For the past three years the results have been published in the Company's Environment, Health and Safety Annual Report. You can obtain a copy of the most recent report by e-mailing webmaster@enbridge.com, or visiting the Enbridge website at www.enbridge.com.

In 2004, the Company's Environment, Health and Safety report will be incorporated into Enbridge's first annual Corporate Responsibility report. The document, expected to be available by mid-year, will take the "triple bottom line" approach to CR reporting and discuss Enbridge's environmental, social and economic performance. It will still provide detailed information about the Company's Environment, Health and Safety performance, but it will also discuss community investment, community consultation, stakeholder relations, human rights and other CR topics.

Financial and Operating Information[1]

(millions of dollars, except per share amounts)

Earnings by Segment	2003	2002	2001	2000	1999
Liquids Pipelines	213.5	189.6	164.4	152.5	146.0
Gas Pipelines	70.1	47.8	41.5	39.6	33.2
Sponsored Investments	234.3	(51.1)	37.2	16.3	30.4
Gas Distribution and Services[2]	153.6	124.3	189.6	211.7	97.7
International	72.3	68.0	35.6	26.4	28.7
Corporate	(76.6)	(44.4)	(55.1)	(88.8)	(48.1)
Continuing operations	667.2	334.22	413.2	357.7	287.9
Discontinued operations[3]	–	242.3	45.3	34.6	–
Earnings applicable to common shareholders	667.2	576.5	458.5	392.3	287.9
Cash Flow Data					
Cash provided from operating activities	395.2	910.6	414.5	263.5	495.1
Expenditures on property plant and equipment	391.3	729.9	683.3	364.3	783.7
Dividends paid on common shares	283.9	251.1	227.5	202.1	186.4
Operating Data					
Liquids Pipelines[4]					
Deliveries *(thousands of barrels per day)*	2,189	2,088	2,109	2,072	1,942
Barrel miles *(billions)*	710	705	695	735	687
Average haul *(miles)*	889	925	903	972	968
Gas Distribution					
Distribution volume *(billion cubic feet)*	458	410	427	421	402
Number of active customers *(thousands)*	1,679	1,623	1,571	1,520	1,466
Degree day deficiency[5] *(degrees Celsius)*					
Actual	4,029	3,362	3,766	3,569	3,460
Forecast based on normal weather	3,565	3,700	3,816	3,629	4,060

1 Certain comparative amounts have been reclassified to conform with the current year's basis of presentation.

2 The highlights of the Gas Distribution activities reflect the results of Enbridge Gas Distribution and other gas distribution assets on a quarter lag basis of consolidation.

3 The results of discontinued operations cannot be disaggregated from continuing operations prior to 2000.

4 Liquids Pipelines operating highlights include the statistics of the 12.2% owned portion of the mainline system located in the United States.

5 Degree day deficiency is a measure of coldness. It is calculated by accumulating for each day in the fiscal period the total number of degrees by which the daily mean temperature fell below 18 degrees Celsius. The figures given are those accumulated in the Toronto area.

Shareholder and Investor Information

(per share amounts in dollars)	2003	2002	2001	2000	1999
Average common shares outstanding weighted monthly during the year *(thousands)*	165,471	160,310	157,297	154,469	150,995
Number of registered common shareholders at year end	7,167	7,406	7,832	8,265	8,877
Common Share Trading *(TSX)* [1]					
High	54.14	49.25	45.55	44.00	36.33
Low	40.95	41.11	33.90	23.00	28.60
Close	53.70	42.61	43.40	43.70	28.65
Volume *(millions)*	75.0	72.3	67.6	68.2	51.8
Per Common Share Data [1]					
Earnings applicable to common shareholders					
Continuing operations	4.03	2.09	2.63	2.32	1.91
Discontinued operations	–	1.51	0.28	0.22	–
	4.03	3.60	2.91	2.54	1.91
Dividends paid on common shares	1.660	1.520	1.400	1.270	1.195
Financial Ratios					
Return on average shareholders' equity [2]	19.9%	19.9%	18.6%	18.6%	14.3%
Return on average capital employed [3]	8.1%	7.5%	7.3%	7.2%	6.6%
Debt to debt plus shareholders' equity [4]	61.4%	64.4%	72.9%	69.4%	68.9%
Debt to total capital employed	52.3%	57.0%	66.3%	61.6%	63.7%
Earnings coverage of interest [5]	3.0x	2.7x	2.2x	2.0x	2.0x
Dividend payout ratio [6]	41.2%	42.2%	48.1%	50.0%	62.6%

1 *Data for 2003, 2002, 2001 and 2000 are for Toronto Stock Exchange only. Prior year data include the Toronto and Montreal stock exchanges.*

2 *Earnings applicable to common shareholders divided by average common equity (weighted monthly during the year).*

3 *Sum of earnings (including earnings from discontinued operations), non-controlling interest and after-tax interest expense divided by average capital employed (weighted monthly during the year). Capital employed is equal to the sum of shareholders' equity, non-controlling interest, future income taxes, deferred credits, and total debt (excluding short-term borrowings which finance gas in storage).*

4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

5 *Sum of earnings before income taxes, non-controlling interest and interest expense, divided by interest expense. Includes earnings from discontinued operations.*

6 *Dividends per common share divided by total earnings per share applicable to common shareholders.*

Common and Preferred Shares
The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preferred Shares, Series A, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.A".

Registrar and Transfer Agent in Canada
CIBC Mellon Trust Company
199 Bay Street
Commerce Court West
Securities Level
Toronto, Ontario M5L 1G9
Telephone: (416) 643-5500
Toll free: (800) 387-0825
Internet: www.cibcmellon.com
CIBC Mellon Trust Company also has offices in Halifax, Montreal, Winnipeg, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States
Mellon Investor Services
85 Challenger Road
Overpeck Centre
Ridgefield Park, NJ, 07660 U.S.A.
Toll free: (800) 526-0801

Preferred Securities
The Preferred Securities, Series B, C and D of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols "ENB.PR.B", "ENB.PR.C" and "ENB.PR.D", respectively. The registrar and transfer agent is Computershare Trust Company of Canada.

Debentures
The registrar and trustee for Enbridge Debentures is Computershare Trust Company of Canada — Montreal, Toronto, Winnipeg, Edmonton and Vancouver

Auditors
PricewaterhouseCoopers LLP

Shareholder Inquiries
If you have inquiries regarding the following:
- Dividend Reinvestment and Share Purchase Plan
- change of address
- share transfer
- lost certificates
- dividends
- duplicate mailings

Please contact the registrar and transfer agent — CIBC Mellon Trust Company in Canada or Mellon Investor Services in the United States.

Other Investor Inquiries
If you have inquiries regarding the following:
- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations

Please contact Enbridge Investor Relations or visit Enbridge's web site at **www.enbridge.com.**

Investor Relations
Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804

Annual and Special Meeting
The Annual and Special Meeting of Shareholders will be held in the Imperial Room at the Fairmont Royal York Hotel, Toronto, Ontario, at 1:30 p.m. EDT on Wednesday, May 5, 2004.

Form 40-F
The Company files annually with the Securities and Exchange Commission of the United States a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company.

Dividend Reinvestment and Share Purchase Plan, and Dividend Direct Deposit
Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. The Company also offers Dividend Direct Deposit which enables shareholders to receive dividends by electronic fund transfer to the bank account of their choice in Canada. Details may be obtained from the Investor Information section of the Enbridge web site at www.enbridge.com, or by contacting CIBC Mellon Trust Company at any of the locations listed above.

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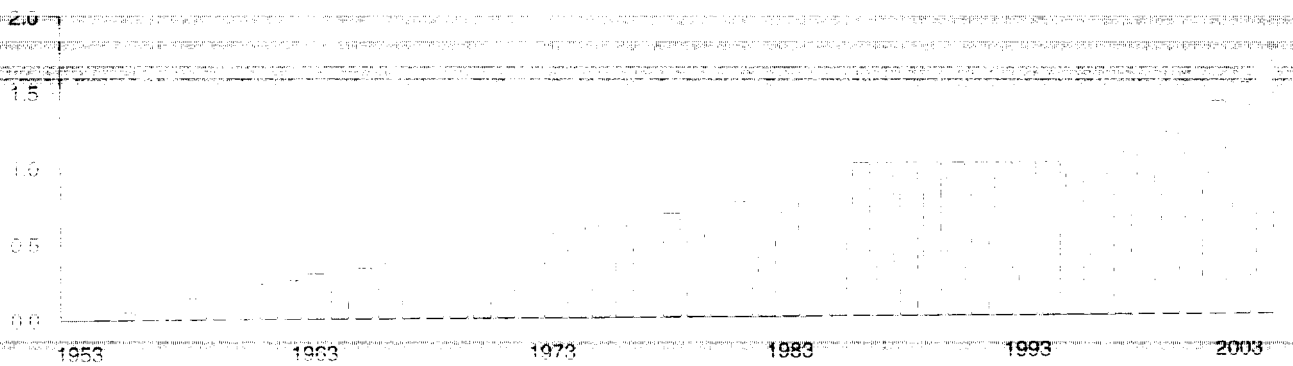
2004 Dividend Information for Common Shares and Preferred Shares, Series A	1st Q	2nd Q	3rd Q	4th Q
Record date	Feb. 13	May 17	Aug. 16	Nov. 15
Payment date	March 1	June 1	Sept. 1	Dec. 1
Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date	Feb. 6	May 10	Aug. 9	Nov. 8
Common Share Purchase Plan cut-off date for DRIP	Feb. 23	May 25	Aug. 25	Nov. 24

** Dividend dates are subject to the dividends being declared by the Board of Directors*

2004 Interest Payment Information for Preferred Securities, Series B, C and D	1st Q	2nd Q	3rd Q	4th Q
Record date	March 15	June 15	Sept. 15	Dec. 15
Payment date	March 31	June 30	Sept. 30	Dec. 31

Le présent document est disponible en français.

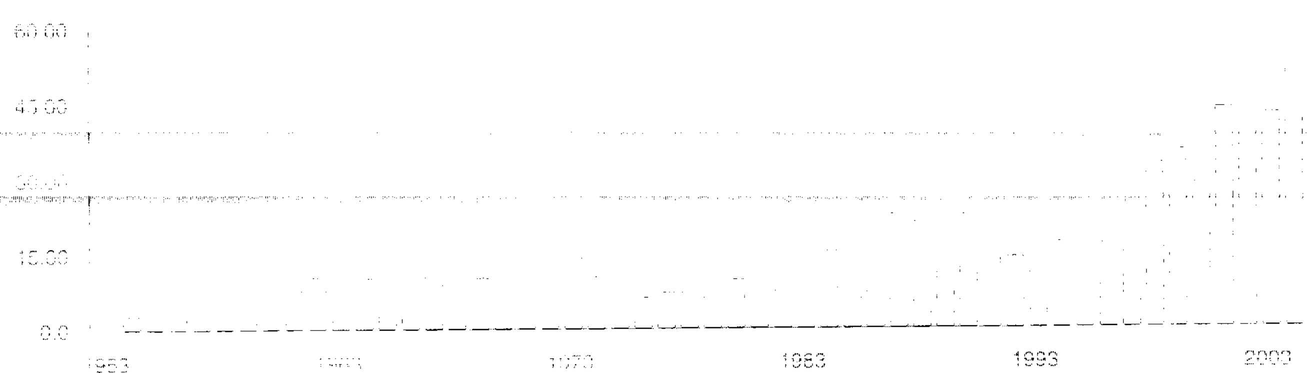
50 Year Annual Dividend



50 Years of Delivering Value to Shareholders. In 2003, Enbridge marked the completion of its 50th year as a publicly traded company — the stock of its predecessor company, Interprovincial Pipe Line Company, Inc., was listed on the Toronto and Montreal stock exchanges on February 13, 1953. The accompanying graphs, showing annual dividends and share price for the 50-year period since the listings, reflect some of the major events in the Company's history — events such as the 1991 spinoff of Home Oil and the creation that same year of Enbridge Energy Partners to own and operate the Lakehead System, and the 1994 acquisition of what is now Enbridge Gas Distribution. The graphs also illustrate the steady, sustained growth that has characterized Enbridge for half a century.

Since 1953, the calculated annual total shareholder return, including dividends, has averaged just over 13%. That's a very positive story for Enbridge shareholders, and an achievement that we at Enbridge are justifiably proud of.

50 Year Share Price



Enbridge common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the U.S. under the symbol "ENB".

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