ENBRIDGE

Value for customers

ENB

Value for shareholders

2005 Annual Report


LK
14MK
OR

At Enbridge, we know that by creating value for our customers we also create value for our shareholders.

Patrick D. Daniel
President & Chief Executive Officer

Enbridge Profile

Enbridge Inc.

A leader

in energy delivery

Enbridge Inc., a Canadian company with corporate headquarters in Calgary, Alberta, Canada, is a leader in energy transportation and distribution in North America and internationally. The Company conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Sponsored Investments (which consist of the Company's investments in Enbridge Energy Partners, L.P.; Enbridge Energy Management, L.L.C.; and Enbridge Income Fund), Gas Distribution and Services, and International.

Infrastructure

80 000

kilometres

Enbridge owns or has interests in 80 000 kilometres of pipelines. That includes more than 25 000 kilometres of crude oil and liquids pipelines, more than 20 000 kilometres of natural gas gathering and transmission pipelines, and more than 30 000 kilometres of natural gas distribution mains.

Crude oil deliveries

2 million

barrels per day

Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids pipeline system – the combined Enbridge Pipelines and Lakehead systems – that delivers 2 million barrels a day to customers in Canada and the United States Midwest, including approximately 10% of total oil imports to the United States. Current expansion plans will move additional volumes of Canadian petroleum to these markets, as well as farther east and south and to the United States West Coast and Asia-Pacific markets.

Natural gas distribution

1.8 million

customers

Enbridge owns and operates Canada's largest natural gas distribution company, and delivers natural gas to 1.8 million customers in Ontario, Quebec, New Brunswick and New York State. Enbridge Gas Distribution, based in Toronto, Ontario, is one of the lowest cost natural gas distribution operations in North America, and has provided reliable service for more than 155 years.

Natural gas pipelines

50%

of deepwater Gulf of Mexico natural gas production

Enbridge has a growing interest in natural gas pipelines in North America. The Company has major interests in the Alliance and Vector transmission systems, and through Enbridge Energy Partners has interests in a variety of transmission and gathering pipeline systems in the Gulf Coast and Mid-Continent regions of the United States. Enbridge Offshore Pipelines transports approximately half of the deepwater offshore natural gas production in the Gulf of Mexico, a key region for continental supply growth.

Renewable energy

270

megawatts of electricity

Enbridge is also investing in renewable energy resources, including wind power and fuel cells. The Company is currently involved in four wind power projects in Canada – two that are currently operating and two being built in 2006 – with a combined capacity of more than 270 megawatts. That's enough electricity to meet the power requirements of more than 100,000 homes.

Publicly traded

TSX, NYSE: ENB

stock exchange listings

Enbridge has been a publicly traded company for 53 years – its predecessor company, Interprovincial Pipe Line Company, Inc., was listed on the Toronto and Montreal stock exchanges on February 13, 1953. Enbridge's common shares now trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the symbol ENB. Information about Enbridge is available on the Company's website at www.enbridge.com.

Human capital

4,500

employees

Enbridge employs approximately 4,500 people – knowledgeable and skilled employees – primarily in Canada and the United States, as well as in Colombia and Spain.

Highlights

2005 adjusted earnings

$1.59

per common share

2005 dividends

$1.0375

per common share

Financial

(millions of Canadian dollars, except per share amounts)	**2005**	2004	2003
Earnings Applicable to Common Shareholders	**556.0**	645.3	667.2
Earnings Per Common Share *(dollars per share)*[1]	**1.65**	1.93	2.02
Dividends Per Common Share *(dollars per share)*	**1.0375**	0.92	0.83
Common Share Dividends Paid	**361.1**	315.8	283.9
Return on Average Shareholders' Equity	**13.2%**	17.0%	19.0%
Debt to Debt Plus Shareholders' Equity at Year End	**68.9%**	67.1%	68.7%

Operating	**2005**	2004	2003
Liquids Pipelines[2]			
Deliveries *(thousands of barrels per day)*	**2,008**	2,138	2,189
Barrel miles *(billions)*	**695**	757	710
Average haul *(miles)*	**949**	970	889
Gas Distribution and Services[3]			
Volume of gas distributed *(billion cubic feet)*	**438**	575	458
Number of active customers *(thousands)*	**1,805**	1,756	1,679
Degree day deficiency[4] *(degrees Celsius)*			
Actual	**3,750**	5,052	4,029
Forecast based on normal weather	**3,747**	4,849	3,565

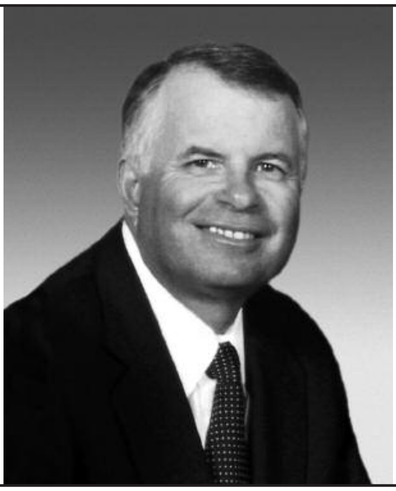
1 All per share amounts have been restated to reflect the Company's two-for-one stock split in May 2005.

2 Liquids Pipelines operating highlights include the statistics of the 10.9% owned Lakehead System and wholly owned liquids pipelines operations.

3 In 2004, Enbridge Gas Distribution (EGD) changed its fiscal year end from September 30 to December 31 to be consistent with Enbridge. Consequently, highlights of Gas Distribution and Services for 2004 include the 15-month period ended December 31 for EGD and other gas distribution operations. Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.

4 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.

Letter to Shareholders



Patrick D. Daniel
President & Chief Executive Officer

David A. Arledge
Chair of the Board

Introductory Remarks

In 2005, Enbridge again added significant value for our customers and our shareholders. The progress made on a large number of greenfield crude oil and natural gas pipeline projects will result in improved access to energy supply for consumers, improved markets for our upstream producers, and economic value for our shareholders. A 9.4% growth in adjusted operating earnings in 2005, coupled with a 25.5% total shareholder return (for shareholders trading on the Toronto Stock Exchange), once again provided shareholders with excellent returns.

Reported earnings were $556 million, or $1.65 per common share, compared with $645 million, or $1.93 per common share in 2004. However, the decrease was primarily due to unusual gains in 2004.

Adjusted operating earnings, which represent earnings applicable to common shareholders adjusted for non-operating factors and variances, reflect Enbridge's continued steady growth. Adjusted operating earnings were $537 million, or $1.59 per common share in 2005, compared with $491 million, or $1.47 per common share in 2004.

We again exited the year with a stronger balance sheet, putting the Company in an excellent position to pursue its "best-ever" slate of greenfield pipeline projects.

Based on this excellent outlook going into 2006, our Board of Directors increased the annual dividend by 15% in November 2005, and indicated a higher target payout range of 60% to 70% of adjusted earnings, up from the previous 50% to 60% range. Enbridge dividends have increased every year since 1996.

Clearly, our Company is well positioned to continue its history of steady growth, and to pursue the creation of value for customers, which in turn results in creation of value for shareholders.

2005 Accomplishments – Working Our Strategies

2005 was also a good year in terms of progress against our four key strategies.

Focus on operational excellence: We successfully concluded a new Incentive Tolling Settlement (ITS) with the Canadian Association of Petroleum Producers – the third such five-year agreement between Enbridge and our customers – based on a negotiated incentive model rather than a traditional cost-of-service model. The ITS has as its foundation the National Energy Board's 2005 multi-pipeline rate of return and provides Enbridge with the opportunity to earn a higher rate of return by achieving certain service and reliability targets, as well as continued achievement of cost savings.

Enbridge continues to operate one of the lowest cost crude oil pipeline systems in North America and one of the lowest cost natural gas distribution companies.

In 2005, we continued to strengthen reporting on our Corporate Social Responsibility program, including environmental, safety and social performance. In September, Enbridge was named to the *Dow Jones Sustainability World Index*, and in January 2006 it was announced at the World Economic Forum in Davos, Switzerland, that Enbridge had once again been named to the list of the *Global 100 Most Sustainable Corporations in the World*.

Expand existing core asset platforms: We made excellent progress on numerous pipeline growth opportunities during 2005.

- The Spearhead Pipeline was reversed and first crude oil shipments reached the Cushing terminal in March 2006. Enbridge now directly ships Western Canadian crude oil all the way from Alberta to Oklahoma.
- In December, we announced that we were proceeding with construction of the Southern Access expansion, to add an additional 400,000 barrels per day of capacity between Superior, Wisconsin and the Chicago, Illinois area by 2009. We are also pursuing commitments for a Southern Access extension to Patoka, Illinois.
- In December, based on first customer commitments, we filed an application to build the Waupisoo Pipeline from the Alberta oil sands to a terminal near Edmonton, Alberta. Waupisoo, which would have initial capacity of 350,000 barrels per day, will be in service in 2008.
- During the year we made significant strides on our Gateway proposal to build a petroleum export pipeline from Edmonton to Kitimat, B.C. and a condensate import pipeline from Kitimat to Edmonton to be in service in 2010. We began environmental fieldwork, continued our consultation with Aboriginal groups and stakeholders, and held 17 informational open houses in communities along the right-of-way. Two Open Seasons produced strong interest from potential customers for both pipelines, and we continue to work to get shipping commitments, continue our community consultations, and complete engineering and environmental planning, to be in position to file an application in the second quarter of 2006 for construction of the pipeline.

All of these projects are needed to accommodate growing oil sands production over the next five to 10 years. In February 2006, we also announced plans for the Enbridge Alberta Clipper Pipeline, a proposed 400,000 barrels per day pipeline from Hardisty, Alberta to Superior, Wisconsin.

We are also developing new infrastructure in the oil sands region of northern Alberta. We announced plans in 2005 to build a pipeline and terminal for a new Fort Saskatchewan upgrader, and invested in Value Creation Inc. to participate in the development of upgrading technologies. At year-end we announced the acquisition of a majority interest in Olympic Pipe Line giving us a position in the U.S. Northwest.

In 2005, we also strengthened our interests in natural gas pipelines in North Texas, and announced plans for an expansion and extension of the Partnership's East Texas natural gas system, to handle the strong growth occurring in East Texas natural gas production, particularly from the Bossier Sands and other regional producing formations. We positioned Enbridge for participation in an Alaska natural gas pipeline, and announced expansion of the Vector pipeline.

Despite the impact of hurricanes last year in the Gulf of Mexico, we are pleased with the footprint of our offshore natural gas pipelines, and we added to our interests in the Gulf because we believe strongly in its potential to be a key source of North American supply for many years to come.

Enbridge Gas Distribution added 50,000 new customers in 2005, and continues to be the second fastest growing gas utility in North America.

Our International investments in Spain and Colombia performed very well in 2005 and provide excellent diversification for our North American focus.

Develop new growth platforms: In addition to our core business opportunities, we pursued opportunities to develop new growth platforms. We see Liquefied Natural Gas (LNG) as a potentially significant contributor to North American supply and we continued to pursue a number of projects – although it's becoming clear that it is going to take time for global LNG production to increase before LNG can make a significant contribution to meeting North America gas demand.

In 2005, we invested in our third wind power project, at Chin Chute, Alberta, and in November we announced a $400 million, 200-megawatt wind power investment to be made in 2006 in Ontario.

Capitalize on Partnership/Trust Model: Our two sponsored investments had good years, as Enbridge Energy Partners completed its East Texas Expansion Pipeline, and continued to position itself as the major transportation company in the Bossier and Barnett Shale gas plays in Texas. Enbridge Income Fund had strong cash flows, which led to another increase in the monthly cash distributions to unitholders. Since inception in mid-2003, monthly cash distributions have increased 11.4%.

In Conclusion

Enbridge is uniquely well positioned for growth, with our extensive and strategically located network of crude oil and natural gas pipeline systems in North America. These assets are ideally situated to deliver new sources of energy supply to a variety of key North American and international markets.

We are financially strong with a low-risk business model that has proven to be very successful. Our Board has declared annual dividend increases averaging 8.5% per year for the past 10 years in a row.

During 2005, we were pleased to welcome Donald J. Taylor back to the Board. Mr. Taylor, the former Chair of the Board, did not stand for re-election as a director at the annual shareholders' meeting in May 2005, having reached the normal age for retirement. However, the Board asked that Mr. Taylor re-join the Board for an additional two years, noting the valuable advice he has provided to Enbridge over the years. We were also pleased to welcome David A. Leslie, the former Chairman and CEO of Ernst & Young LLP, to the Enbridge Board in July 2005.

Louis D. Hyndman, a Director since 1993, will retire from the Board effective with the next shareholders' annual meeting on May 3, 2006, and we thank Mr. Hyndman for his many contributions to Enbridge and for his years of service, most recently as Chair of the Corporate Social Responsibility Committee.

In conclusion, we would like to thank the employees of Enbridge for their outstanding contributions in 2005. All of us at Enbridge will continue to work diligently to continue to add value for our shareholders, our customers, our business partners, and the communities where we live and work.

On behalf of the Board of Directors:

David A. Arledge
Chair of the Board of Directors
March 3, 2006

Patrick D. Daniel
President & Chief Executive Officer

Strategies and Fundamentals

Enbridge has numerous growth opportunities within each of its core businesses, and is well positioned geographically to deliver new sources of energy supply to North American markets.

Enbridge will pursue

4

key strategies for growth

- Expand existing core businesses.
- Develop new growth platforms, such as LNG regasification, marketing and storage, gas-fired power generation, wind power and new energy technologies.
- Capitalize on the Partnership/Trust Model. Enbridge Energy Partners and Enbridge Income Fund will develop or acquire energy infrastructure assets.
- Focus on operational excellence.

And will expand

4

core businesses

- Expand the **Liquids Pipelines** business by developing regional Alberta oil sands infrastructure, increasing capacity to traditional markets, and pursuing new market initiatives.
- Expand and develop the existing **Gas Distribution and Services** businesses.
- Expand the **Natural Gas Pipelines** business – Alliance, Vector and Enbridge Offshore Pipelines systems – and pursue new infrastructure such as an investment in an Alaska natural gas pipeline.
- Expand **International** investment focusing on Europe and Latin America.

Enbridge's growth opportunities are built around North America's energy supply/demand fundamentals. The Company is ideally positioned to transport crude oil and natural gas from conventional producing areas in Western Canada and from the continent's largest hydrocarbon play – Alberta's oil sands. Enbridge is also well positioned to tap some of North America's energy growth hotspots: Alaska, the Gulf of Mexico, Texas and the Rockies. With the existing integration of markets between Canada and the United States, growing energy demand, Canada's history of being a secure source of energy supply, and Enbridge's extensive continental pipeline systems, Enbridge will be a major contributor to meeting continental energy needs.

Enbridge listens to what the market is saying, and listens to where demand is going to be for hydrocarbons and where the expected new supply is. The Company also spends a lot of time communicating and consulting with customers to ensure we are meeting their needs.

Forecast incremental growth in oil sands production

1 million

barrels per day by 2010

An estimated $60 billion of investment has been announced for projects in the oil sands in northern Alberta. Based on projects under construction and projects announced, industry forecasts indicate oil sands production will increase by approximately 1 million barrels per day by 2010.

Planned liquids pipelines investments

$8 billion

over five years

Enbridge and Enbridge Energy Partners currently plan on investing more than $8 billion by 2010 to add to their liquids pipelines capacity to deliver growing oil sands volumes. The investments will include new oil sands infrastructure – pipelines and tankage – to deliver oil sands production to Edmonton and Hardisty, Alberta; additional capacity to traditional markets in the U.S. Midwest, as well as farther east and south in the United States; and the Gateway Pipeline to access U.S. West Coast and Asia-Pacific markets.

Enbridge has an extensive North American network of pipeline systems that historically has transported approximately two-thirds of Western Canadian crude oil production to markets. As such, Enbridge is well positioned with assets between areas of growing supply and growing demand.

That is particularly true with regard to oil sands development, where the rapid growth in oil sands projects is expected to add in the order of 1 million barrels per day of new production by 2010.

Enbridge has been working with its customers for the past five years to ensure the right pipeline capacity is in place at the right time for the right markets, and currently expects to invest more than $8 billion by 2010 just on liquids pipeline projects such as Athabasca, Waupisoo, Southern Access, Spearhead, Gateway and mainline expansion. Additional projects, involving additional expenditures, are also being developed.

Successful completion of these projects will produce a classic win-win result. Oil sands producers will have timely and cost-effective access to markets for their growing production, and expanded markets will help maximize netbacks. North American consumers will benefit from having access to new, secure sources of supply that will continue to produce petroleum for many decades to come.

Enbridge participated in another win-win outcome in 2005. The Company and the Canadian Association of Petroleum Producers (CAPP) reached agreement on the key terms of a new five-year incentive tolling settlement for 2005 through 2009 for the core component of Enbridge's mainline liquids pipeline system in Canada.

Incentive Tolling Settlement benefits

$119 million

shared after tax

Since the inception of incentive tolling in 1995, after-tax benefits of $119 million have been shared by Enbridge and its customers, approximately 53% and 47%, respectively. Customers also realized an additional cumulative after-tax benefit of $16 million through the power guarantee mechanism of the ITS.

Forecast growth at Enbridge Gas Distribution

200,000

new customers in the next five years

Enbridge Gas Distribution, Enbridge's natural gas distribution franchise in Ontario, is the second fastest growing gas utility in North America. For the past nine years, Enbridge Gas Distribution has added between 50,000 and 60,000 new customers per year, and expects to continue to grow at a similar pace, forecasting more than 200,000 new customers in the next five years.

Enbridge and CAPP both realized significant benefits under the two previous incentive tolling agreements, which covered the periods 1995 to 2004, and both recognized the benefits of continuing to use a negotiated incentive toll model rather than a traditional cost-of-service model. In the first 11 years of incentive tolling, after-tax benefits of $119 million were shared by Enbridge and its customers.

Enbridge is also well positioned geographically for growth in natural gas pipelines – in the Gulf of Mexico, in the growing Texas Barnett Shale, Anadarko Basin and Bossier gas plays, and between a potential Alaskan natural gas pipeline and key North American markets.

The addition of new sources of natural gas supply to meet growing demand in North America is essential to avoid shortfalls as traditional sources of supply peak. Enbridge is well positioned, as a pipeline company, to transport that natural gas to markets. In addition, as Canada's largest natural gas distribution company, which expects to add more than 200,000 new customers in the next five years, Enbridge Gas Distribution is interested, as a customer, in new sources of gas supply.

Total shareholder return

25.5%*

in 2005

Enbridge's objective is to provide superior long-term value for shareholders, and the Company has consistently delivered strong total shareholder returns. In 2005, the total shareholder return was 25.5%

* *Total shareholder return includes total cash dividends declared plus common share price appreciation. This is not a standardized measure under Canadian Generally Accepted Accounting Principles, therefore it may not be comparable to similarly titled measures used by other issuers.*

Dividend payout target

60-70%

of earnings

In November 2005, the Board of Directors approved a revised dividend policy for Enbridge that will see Enbridge target to pay out approximately 60% to 70% of earnings, an increase from the recent 50% to 60% target range. The change takes into consideration a robust growth outlook combined with the increased attractiveness that many investors are assigning to dividend income, providing Enbridge investors with an attractive combination of strong long-term growth and favourable near-term cash payout.

By being a part of the delivery solution, Enbridge helps provide customers with new long-term sources of supply. That, in turn, will bring greater price stability to markets throughout North America, benefiting all natural gas consumers.

When customers benefit, Enbridge shareholders benefit. In the 53 years that Enbridge has been a publicly traded company, Enbridge shareholders have received an average annual total shareholder return of 13.3%. In the past 10 years alone, the return has averaged 20.9%, and in 2005, the return was 25.5%. Clearly, customer value has translated into shareholder value.

In November 2005, the Enbridge Board of Directors added further value for shareholders by announcing that the Company was increasing its dividend target to pay out between 60% and 70% of earnings. Shareholders receive a direct benefit while the Company retains ample balance sheet capacity and the ability to fund its large portfolio of growth projects.

Corporate Governance

At Enbridge, corporate governance means ensuring that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

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.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance in respect of the strategic plan of the Company. The Board also monitors implementation.

The Board approves all significant decisions that affect the Company and reviews the results. The Board also oversees identification of the principal risks to the Company on an annual basis, monitors the Company's risk management programs, reviews succession planning, and seeks assurance that internal control systems and management information systems are in place and operating effectively.

Additional information and details about Enbridge's corporate governance policies and practices are available in the Company's annual Management Information Circular, and in the corporate governance section of the Company's website, at www.enbridge.com/investor/corporateGovernance.

Corporate Social Responsibility

Community investment

$4.8 million

in Canada in 2005

Enbridge continues to invest in communities where the Company operates, primarily in health, social services, education, the environment, arts and culture, and civic leadership. For the sixth year in a row, Enbridge was recognized by the United Way and Centraide as a recipient of their *Thanks a Million Award* for raising more than $1 million for United Way and Centraide campaigns in Canada.

Global 100 Most Sustainable Corporations in the World

1 of 5

Canadian companies named to the listing in 2006

The *Global 100 Most Sustainable Corporations in the World* is a new global ranking that reviewed 2,000 companies for their ability to manage environmental, social and governance risks and opportunities. Enbridge was named to the listing of 100 companies that was announced at the World Economic Forum at Davos, Switzerland, in January 2005. Enbridge was again named to the listing in January 2006, one of only five Canadian companies.

Corporate Social Responsibility (CSR) is about conducting business in a socially and environmentally responsible manner. It is a process of constant innovation, a team effort to understand and deal with many complex and evolving issues involving our many stakeholder groups, and it goes to the heart of the Company's values and how it does business.

Enbridge's approach to Corporate Social Responsibility and its CSR performance are detailed in the Company's 2005 Corporate Social Responsibility Annual Report. The report, which reviews Enbridge's environmental, economic and social performance, was once again written in compliance with the guidelines outlined in the Global Reporting Initiative's 2002 Sustainability Reporting Guidelines. In addition, selected information and indicators in the current report were subject to an internal review by Enbridge's Audit Services Department.

A copy of the annual report is available in the CSR section of Enbridge's website, at www.enbridge.com/corporate/.

Board of Directors

Top Row (left to right)

David A. Arledge
Naples, Florida
Chair, Enbridge Inc.

James J. Blanchard
Beverly Hills, Michigan
Senior Partner,
DLA Piper Rudnick Gray Cary
U.S., LLP

J. Lorne Braithwaite
Malahide, County Dublin, Ireland
Corporate Director

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

E. Susan Evans
Calgary, Alberta
Corporate Director

William R. Fatt
Toronto, Ontario
Chief Executive Officer,
Fairmont Hotels & Resorts Inc.

Bottom Row (left to right)

Louis D. Hyndman
Edmonton, Alberta
Counsel, Field Law LLP

David A. Leslie
Toronto, Ontario
Corporate Director

Robert W. Martin
Toronto, Ontario
Corporate Director

George K. Petty
San Luis Obispo, California
Corporate Director

Charles E. Shultz
Calgary, Alberta
Chair & Chief Executive Officer,
Dauntless Energy Inc.

Donald J. Taylor
Jacksons Point, Ontario
Corporate Director

Senior Management

Top Row (left to right)

Patrick D. Daniel
President & Chief Executive Officer

Mel F. Belich
Group Vice President, Corporate Law

J. Richard Bird
Group Vice President, Liquids Pipelines

Bonnie D. DuPont
Group Vice President, Corporate Resources

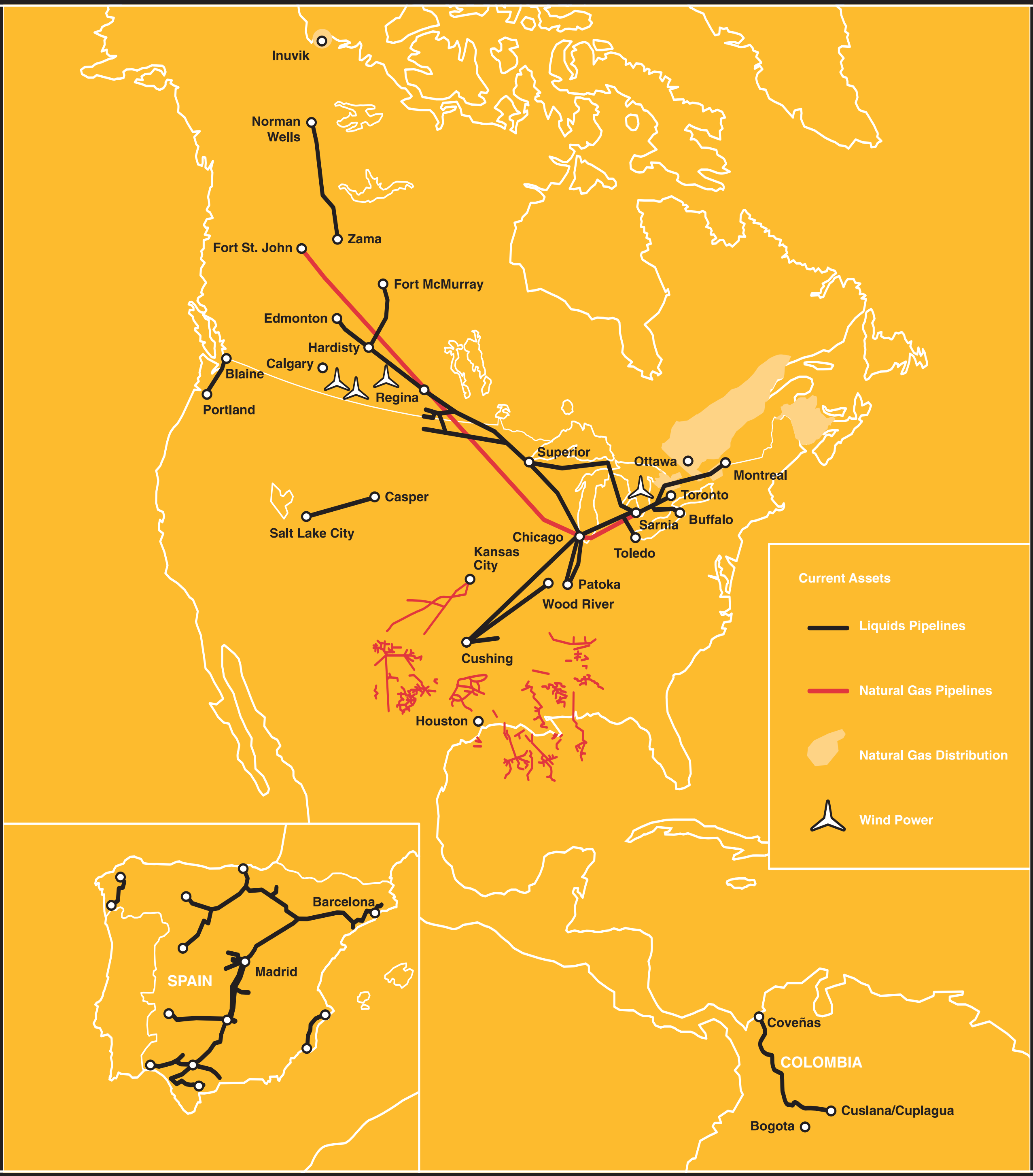
Bottom Row (left to right)

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

Dan C. Tutcher
Group Vice President, Transportation South

Stephen J. Wuori
Group Vice President & Chief Financial Officer

Enbridge Businesses



Enbridge continues to broaden its footprint in North America – an important consideration for a company in the energy delivery business. In so doing, the Company has focused on adding assets between areas of growing supply and areas of growing demand.

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 (100%)
- Olympic Pipe Line Company (65%)
- Hardisty Caverns Limited Partnership (50%)

Gas Pipelines

- Alliance Pipeline L.P. (U.S. portion) (50%)
- Vector Pipeline Limited Partnership (60%)
- Enbridge Offshore Pipelines, L.L.C. (100%)

Sponsored Investments

- Enbridge Energy Partners, L.P. (10.9%)
  - Lakehead System
  - North Dakota System
  - Mid-Continent System
  - Various Natural Gas Systems
- Enbridge Income Fund (72.3% overall economic interest)
  - Enbridge Pipelines (Saskatchewan) Inc. (100%)
  - Alliance Pipeline Limited Partnership (Canadian portion) (50%)

Gas Distribution and Services

- Enbridge Gas Distribution (100%)
  - St. Lawrence Gas Company, Inc.
- Gazifere Inc. (100%)
- Niagara Gas Transmission Limited (100%)
- Noverco Inc. (32.1%), which owns:
  - Gaz Métro Limited Partnership (72.8%), 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 (64%)
- CustomerWorks Limited Partnership (70%)
- Enbridge Commercial Services Inc. (100%)
- Aux Sable Liquids Products Inc. (42.7%)
- Enbridge Gas Services Inc. (100%)
- Inuvik Gas Ltd. (33.3%)
- Tidal Energy Marketing Inc. (100%)
- Value Creation Inc. (strategic alliance)
- NetThruPut Inc. (52%)
- SunBridge Wind Power Project (50%)
- Magrath Wind Power Project (33.3%)
- Chin Chute Wind Power Project (33.3%)
- Enbridge Ontario Wind Power Project LP (100%)
- FuelCell Energy (strategic alliance)

International

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

Financial Review

In 2005, strong earnings contributions from all of Enbridge's core businesses and a strong financial position enabled Enbridge to continue to add value for shareholders.

Management's Discussion and Analysis

CONSOLIDATED RESULTS

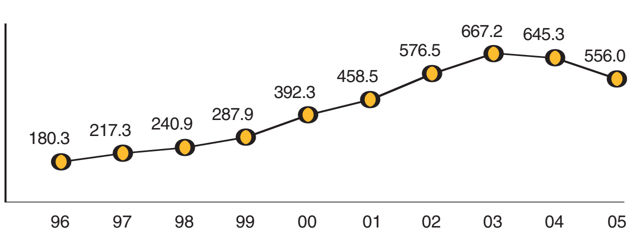
Financial Highlights[1]

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

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

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

Earnings applicable to common shareholders for the year ended December 31, 2004, were $645.3 million, or $1.93 per share compared with $667.2 million, or $2.02 per share, for the year ended December 31, 2003. In addition to the factors noted above, the 2004 results included a full year of incremental earnings from the Terrace Phase III mainline expansion, rate increases and positive variances from forecast costs in Enbridge Gas Distribution, and improved fractionation margins in Aux Sable compared with 2003. These positive factors in 2004 were offset by the absence of earnings from Alliance Pipeline Canada and Enbridge Saskatchewan, which were sold in June 2003 to Enbridge Income Fund for a gain of $169.1 million.



Earnings Applicable to Common Shareholders
(millions of Canadian dollars)

Earnings for 2005 included earnings from Enbridge Offshore Pipelines, acquired at year-end 2004; a higher contribution from the gas utility; and lower interest expense. Earnings in 2004 included an after-tax gain of $97.8 million on the sale of the investment in AltaGas Income Trust, as well as 15 months of earnings for gas distribution utilities reflecting the change in year end for those entities. Earnings in 2003 included a $169.1 million after-tax gain on the sale of assets to Enbridge Income Fund.

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

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

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

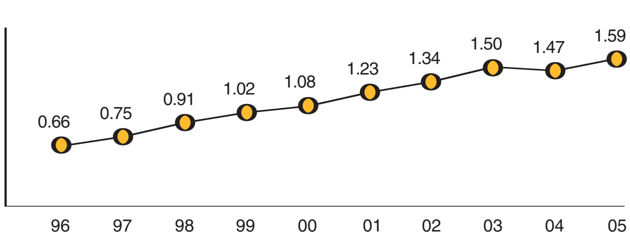
2 This adjustment reflects EGD's 2003 earnings on the calendar basis. Prior to EGD's change in fiscal year end in 2004, described above, EGD's earnings were consolidated on a one-quarter-lag basis. As a result, reported consolidated results for the year ended December 31, 2003, included EGD's results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

Significant operating factors affecting earnings in 2005 include:

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

Enbridge completed several strategic initiatives during 2005:

- Negotiated new five year Incentive Tolling Settlement on the Enbridge System.
- Obtained founding shipper agreements underpinning the $400 million Waupisoo Pipeline and filed an application for regulatory approval.
- Confirmed shipper support for both the Gateway Petroleum Export Pipeline and the Gateway Condensate Import Pipeline, through non-binding open seasons, supporting continued preparations to file a full regulatory application in 2006.



Adjusted Earnings per Common Share

(dollars per share)

Adjusted operating earnings represent earnings applicable to common shareholders adjusted for non-operating factors and variances. This is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure. Therefore, this measure may not be comparable with a similar measure presented by other issuers. Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends.

- Secured the BA Energy Upgrader $80 million terminaling and pipeline services agreement as the initial customer for our new Stonefell terminal at Fort Saskatchewan, Alberta.
- Substantially completed the US$190 million Spearhead Pipeline project to deliver Canadian crude oil, for the first time, down to the major hub at Cushing, Oklahoma.
- Secured shipper support and commenced field work for the US$950 million, 400,000 barrels per day (bpd) Southern Access mainline expansion project being undertaken by Enbridge and Enbridge Energy Partners.
- Entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all of the power to be produced from the $400 million, 200-megawatt wind power project currently under development by Enbridge on the shores of Lake Huron.
- Entered into an agreement to purchase 65% of the Olympic Pipe Line Company, a refined products pipeline in Washington State, for US$99.8 million.

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

CORPORATE STRATEGY

Corporate Vision and Objective

Enbridge is an energy delivery company that delivers natural gas and crude oil, which are used to heat homes, power transportation systems, and provide fuel and feedstock for industries. The Company's vision is to be North America's leading energy delivery company and its objective is to generate long-term value for investors. The key elements of this vision are to:

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

Core Businesses

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

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

Organic Growth Projects

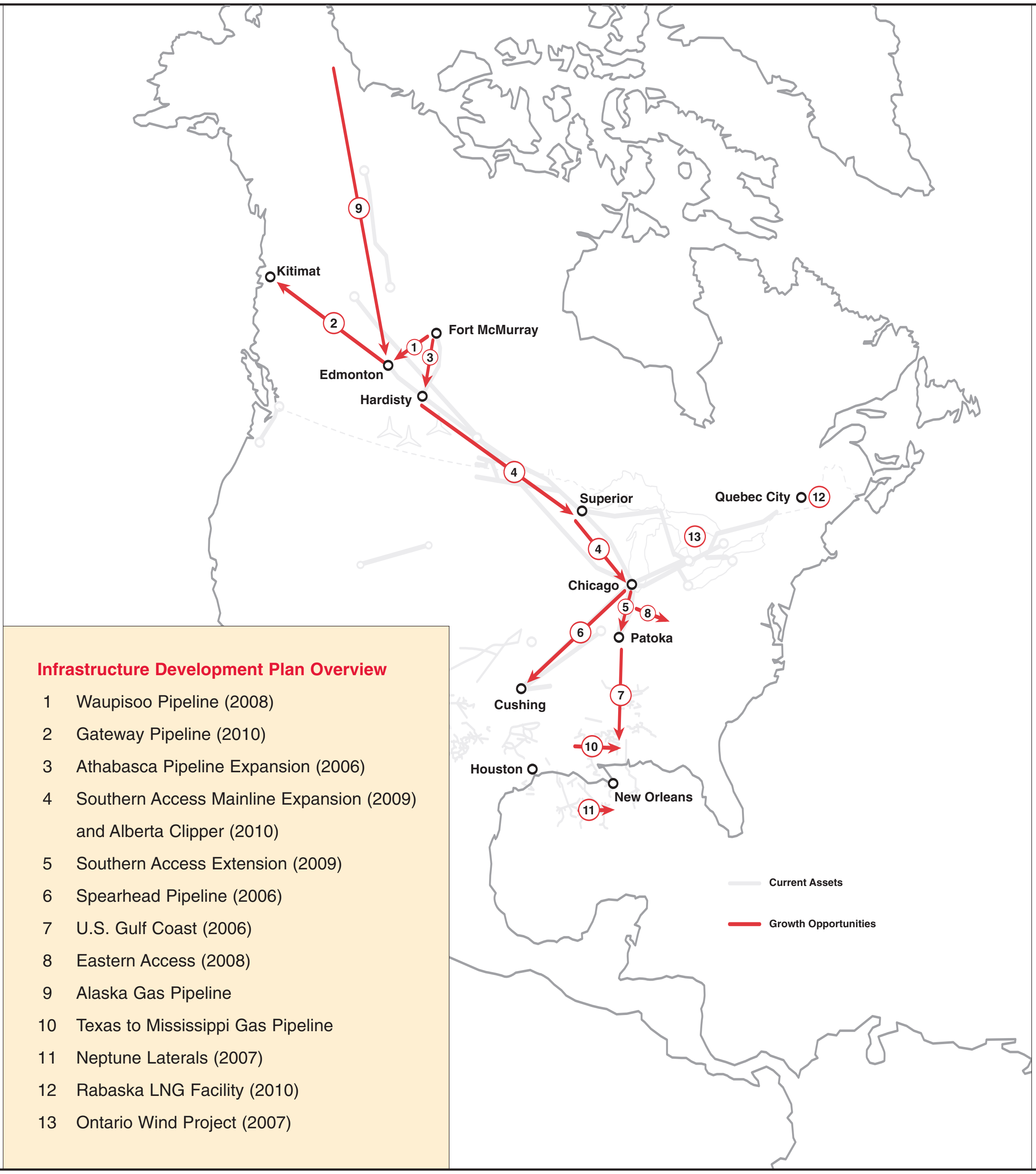
A key focus of the Company's strategy is growth through internally developed organic projects. The Company is targeting organic growth rates averaging 6% over the next five years. The Company is advancing the development of a number of organic growth projects, some of which are summarized below. Enbridge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

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

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

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

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



Infrastructure Development Plan Overview
1 Waupisoo Pipeline (2008)
2 Gateway Pipeline (2010)
3 Athabasca Pipeline Expansion (2006)
4 Southern Access Mainline Expansion (2009) and Alberta Clipper (2010)
5 Southern Access Extension (2009)
6 Spearhead Pipeline (2006)
7 U.S. Gulf Coast (2006)
8 Eastern Access (2008)
9 Alaska Gas Pipeline
10 Texas to Mississippi Gas Pipeline
11 Neptune Laterals (2007)
12 Rabaska LNG Facility (2010)
13 Ontario Wind Project (2007)
Kitimat
Fort McMurray
Edmonton
Hardisty
Superior
Quebec City
Chicago
Patoka
Cushing
Houston
New Orleans
Current Assets
Growth Opportunities

Dividends

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

Strategy

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

1. Expand Existing Core Asset Platforms

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

2. Develop New Growth Platforms

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

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

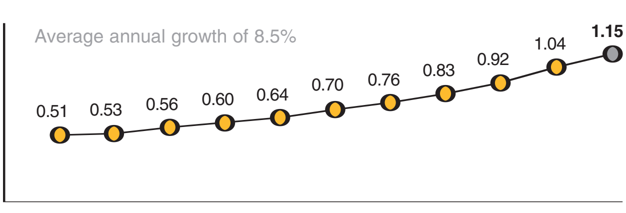
3. Capitalize on the Partnership/Trust Model

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

4. Focus on Operational Excellence

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

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



Dividends per Common Share

(dollars per share)

Dividends per common share have increased an average of 8.5% per year since 1996. They were further increased in 2005, and are expected to be $1.15 per common share for full-year 2006 assuming the Board does not further increase the dividend subsequent to the November 2005 increase.

Corporate Social Responsibility

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

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

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

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

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

LIQUIDS PIPELINES

Earnings

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

Business Activities

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

Enbridge System

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

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

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

In 2005, Enbridge and the Canadian Association of Petroleum Producers (CAPP) approved the key terms of a new negotiated ITS, effective for January 1, 2005, to December 31, 2009. In January 2006, the NEB approved the new ITS. The new ITS continues the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In conjunction with the Terrace Agreement, the new ITS continues the throughput protection provisions ensuring the Company is insulated from negative volume fluctuations beyond its control. In addition to the incentive-based provisions in prior agreements, service and reliability metrics, collectively performance metrics, have been added to the new ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets under the new performance metric provisions.

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

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

Athabasca System

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

The Company has a long-term (30 year) take or pay contract with the major shipper on the Athabasca System, which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning return on equity, based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns, as well as the cost of providing service. Therefore, Enbridge is recording a receivable in these years ensuring that the revenue recognized each period is in accordance with the agreement. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

NW System and Others

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

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

Results of Operations

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

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

Enbridge System

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

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

Athabasca System

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

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

NW System

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

Feeder Pipelines and Other

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

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

Strategy

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

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

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

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

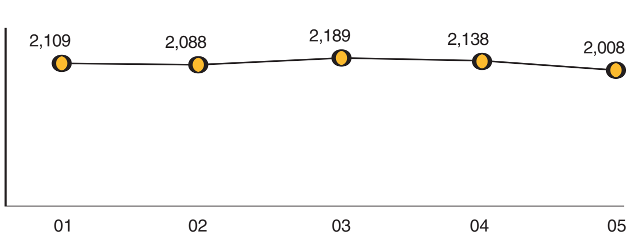
Supply and Reserves

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

1 *National Energy Board 2005 Estimate Production of Canadian Crude Oil and Equivalent Table 1*
2 *Canadian Association of Petroleum Producers Statistical Handbook 2005*
3 *Alberta Energy and Utilities Board Alberta's Reserves 2004 and Supply/Demand Outlook*
4 *Oil and Gas Journal's Worldwide Look at Reserves and Production, December 19, 2005*

Demand for WCSB Crude

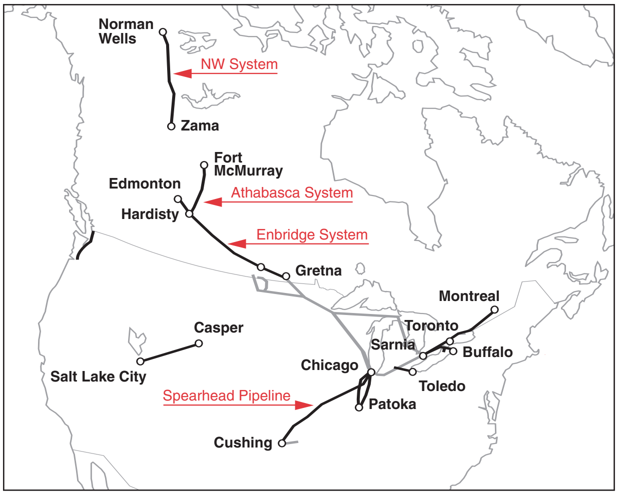
The Company's liquids pipelines are dependent upon the demand for crude oil and other liquid hydrocarbons produced from Western Canada. Historically, the pipeline system has delivered crude oil to two main markets: Ontario/Quebec, and the Midwest portion of the United States with some volume delivered to Western Canada. Through Company initiatives, crude oil will begin to penetrate southern markets in PADD II with the Spearhead Pipeline as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.



Deliveries[1]
(thousands of barrels per day)

Deliveries declined in 2005 as a result of a fire at an oil sands plant. However, development of the oil sands is expected in future to offset declining conventional production, and total Western Canada production – and Enbridge deliveries – are expected to grow significantly.

1 *Includes deliveries by the 10.9% owned Lakehead System*



Liquids Pipelines

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

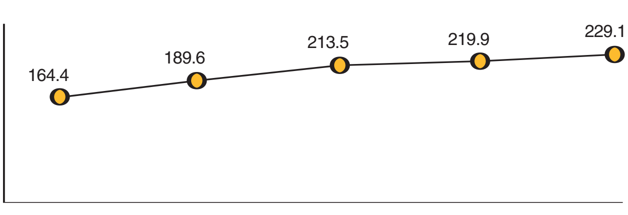
The abundance of established reserves from oil sands, the proximity to the U.S. markets and the relative geopolitical attractiveness of the resource, as well as strong demand, will provide opportunities for the expansion of Enbridge's Athabasca System and the Enbridge System as well as the development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

Alberta Oil Sands Infrastructure

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

The Gateway Project

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



Liquids Pipelines Earnings

(millions of Canadian dollars)

Liquids Pipelines earnings increased in 2005 due to higher Athabasca System earnings and improved earnings from Feeder Pipelines and Other, primarily Frontier Pipeline.

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

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

Waupisoo Pipeline Project

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

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

Surmont Oil Sands Project

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

Long Lake Oil Sands Project

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

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

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

Athabasca Pipeline Expansions

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

Market Penetration and Access

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

Southern Access Mainline Expansion and Extension Program

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

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

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

Alberta Clipper Pipeline

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

Spearhead Pipeline

Enbridge acquired 90% of the Spearhead Pipeline in 2003 and the remaining 10% in 2005. The Company is reversing the flow of the pipeline, which previously operated from Cushing to Chicago, to bring crude oil from Chicago to Cushing. The Spearhead Pipeline project is currently estimated to result in a total investment of $230 million, of which approximately $220 million has been spent. The reversed pipeline is expected to be in service in March 2006.

Other Projects

Contract Terminaling

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

Stonefell Terminal

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

Olympic Pipe Line

In December 2005, Enbridge announced that it will acquire a 65% interest in the Olympic Pipe Line Company (Olympic) from BP for US$99.8 million, subject to working capital adjustments. The transaction closed on February 1, 2006. Olympic owns the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland and consists of 640 kilometres (400 miles) of 6-to-20 inch diameter pipe, a 500,000-barrel products terminal, 9 pumping stations and 21 delivery points or facilities. Olympic is the sole supplier of jet fuel to the Seattle-Tacoma International Airport and is a major supplier to the Portland International Airport. BP will continue to operate the pipeline system.

Customer and Stakeholder Relationships

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

Capital Expenditures

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

Legal Proceeding – CAPLA Claim

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

Business Risks

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

Supply and Demand

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

Performance Metrics

The new ITS governing the Enbridge System measures the Company's performance in areas key to customer service. If the Company fails to meet the baseline targets set out in the new ITS, for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $25 million in 2006 and 2007 and $30 million in 2008 and 2009.

Regulation

Earnings from the Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from these operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity. For 2006, this rate of return is 8.88%. To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk can be reduced through the negotiation of long-term agreements with shippers.

Competition

Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, and proximity to markets. Other common carriers are available to producers to ship Western Canadian crude oil to refineries in either Canada or the United States. Although the Company does not compete directly in the regions served by these other pipelines, producers can elect to have their crude oil refined at delivery points not on the Enbridge System. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls. Also, the ITS and the Terrace Agreement on the Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection and is exposed to volume fluctuations.

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

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

GAS PIPELINES

Earnings

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

Business Activities

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in the US portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising the Enbridge Offshore Pipelines. Alliance Pipeline Canada was sold to EIF effective June 30, 2003. EIF is included in Sponsored Investments.

Alliance Pipeline US

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 700-kilometre (440-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois and has the capacity to deliver 1.55 billion cubic feet per day (bcf/d).

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

Alliance connects with a natural gas liquids (NGL) extraction facility (Aux Sable) in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the Midwestern and northeastern United States and eastern Canada. Aux Sable is owned 42.7% by Enbridge and its results are included under Gas Distribution and Services.

Vector Pipeline

The Company provides operating services to, and holds a 60% investment in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.0 bcf/d and is operating at or near capacity. Vector Pipeline's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. Approximately 70% of the long haul capacity of Vector Pipeline is committed to long-term, 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and various term lengths. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service.

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

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines (EOP) is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. The operations were purchased December 31, 2004. These pipelines include almost 2,400 kilometres (1,500 miles) of underwater pipe and onshore facilities and transport more than half of all current deepwater Gulf of Mexico natural gas production. These pipelines normally transport approximately 2.7 bcf/d.

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

The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria but also provide the shippers with flexibility given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

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

Results of Operations

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

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

Alliance Pipeline US

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

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

Vector Pipeline

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

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

Enbridge Offshore Pipelines

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

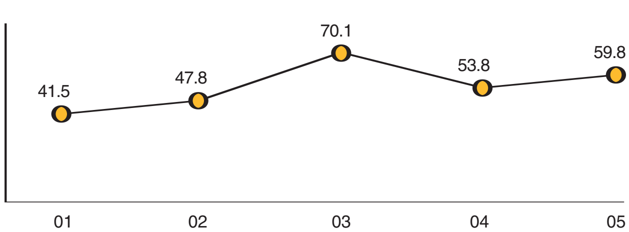
As of December 31, 2005, the pipelines were transporting 90% of pre-hurricane volumes, or approximately 2.4 bcf/d, compared with the pre-hurricane rate of approximately 2.7 bcf/d. The impact on each corridor is described below.

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

Hurricane Katrina caused modest damage to certain Enbridge assets in the Destin Corridor. However, upstream and downstream oil and natural gas liquids pipelines facilities owned by others experienced damage and were not operational until mid-October. Operations were restored by the end of October with production throughput continuing to increase as repairs of non-Enbridge facilities were completed. As of December 31, 2005, volumes on the Destin Corridor were up to 0.89 bcf/d which is approximately 95% of the pre-hurricane level.

Hurricane Rita caused no material incremental damage to the Mississippi Canyon and Destin Corridors.

Hurricanes Katrina and Rita caused no material damage in the Green Canyon Corridor and volumes were unaffected by the hurricanes.



Gas Pipelines Earnings
(millions of Canadian dollars)

Earnings from Gas Pipelines increased in 2005 as a result of the addition in 2005 of earnings from Enbridge Offshore Pipelines. Earnings from Alliance Pipeline US and Vector Pipeline were modestly lower due to the stronger Canadian dollar in 2005.

The Garden Banks and Stingray Corridors were in the direct path of Hurricane Rita. In these corridors, there was minimal damage to the Enbridge owned offshore pipelines and platform facilities. In the Garden Banks Corridor, volumes returned to pre-hurricane levels in mid-November when repairs to an upstream producer gathering line were completed. Volumes on the Stingray pipeline began flowing again in early November at a rate of approximately 0.1 bcf/d and were at 0.325 bcf/d by year-end or 65% of pre-hurricane levels. Volumes are expected to return to pre-hurricane levels in early 2006 following completion of repairs to the Stingray onshore plant facility scheduled for January 2006 and repairs to third party processing facilities.

Strategy

The five main elements of the Gas Pipelines strategy are: (i) continue to expand the existing Alliance and Vector systems and position them for northern gas development; (ii) capitalize on the offshore Gulf of Mexico assets through continued joint venture consolidation, connection of new gas discoveries and acquisition of other deepwater systems; (iii) consolidate Enbridge's assets in the Chicago-to-Dawn corridor and extend its presence downstream of Dawn; (iv) achieve an equity participation in an Alaska-to-Alberta gas pipeline in partnership with producers; and (v) pursue and develop pipeline infrastructure required to move U.S. Rockies gas to the Midwest and northeastern markets. The strategy is based on the Company's assessment of the supply and demand for natural gas.

Supply and Demand for Natural Gas

North American natural gas demand is expected to grow at a modest rate for the next three to five years primarily driven by growth in power generation, which more than offsets declines in industrial demand. The re-emergence of coal as a generation source, due to advances in clean-coal technology, as well as the re-emergence of nuclear power as a source of electricity generation will mitigate growth in the demand for natural gas in that sector. The development of oil sands projects in Alberta also impacts the demand for natural gas, as various extraction and upgrading processes require the use of natural gas. Demand growth is expected to be constrained by recent strong prices and increased volatility due to supply concerns from traditional sources. Over time, the entry of new supplies from the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as Liquefied Natural Gas are expected to alleviate supply concerns and provide opportunities for Enbridge to deliver this natural gas to markets.

To respond to this expected growth in demand, Enbridge will further develop its existing gas pipelines investments and pursue new growth platforms including an increased presence in the Gulf of Mexico. Offshore development is expected to include options that offer both crude oil and natural gas transportation. Alliance will focus on cost-effective optimization, more efficient maintenance practices and increased heating values. Alliance is well positioned to participate in the delivery of Alaska/Mackenzie Delta gas to markets in the United States. Vector's strategy will focus on ensuring a safe and cost-efficient expansion for a late-2007 in-service date. New growth platforms could include significant ownership in a pipeline transporting gas from the U.S. Rockies; ownership in a pipeline connecting Dawn, Ontario, to New York State; storage facilities in Ontario and a significant ownership position in other storage facilities; as well as the pursuit of an equity participation in the Alaska-to-Alberta gas pipeline.

The Company continues to pursue developments in the Gulf of Mexico, building on its initial $754 million investment in EOP. During 2005, Enbridge increased its interest in Garden Banks Gas Pipeline and Neptune Pipeline Company, two systems within EOP. The Company believes that gas production from the deepwater Gulf of Mexico will increase from pre-Hurricane Katrina flows of 3.5 to 4.0 bcf/d to approximately 8 bcf/d by 2010. Strategically, the Company believes that its status as an independent operator, not a producer, will allow for the further consolidation of joint venture interests across the Gulf of Mexico. Further growth is anticipated from connecting new leases and entry into oil pipelines.

Neptune Project

The Company plans to construct and operate both a natural gas lateral and a crude oil lateral to connect the deepwater Neptune oil and gas field in the Green Canyon Corridor to existing Gulf of Mexico pipelines, extending Enbridge's existing

Gulf of Mexico infrastructure. The laterals are expected to cost a total of approximately US$125 million and will have the capacity to deliver in excess of 200 mmcf/d of gas and approximately 50,000 bpd of oil. Construction of the Neptune oil and gas laterals is scheduled for the second quarter of 2007 with first throughput expected by year-end 2007.

Capital Expenditures

The Company expects to spend approximately $100 million in 2006 in the Gas Pipelines segment for on ongoing capital improvements, core maintenance capital projects and expansion, including the Neptune Project described above.

Business Risks

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

Alliance Pipeline US and Vector Pipeline

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess supply environment mainly because of long-term capacity contracts going to 2015. Vector Pipeline could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll.

Exposure to Shippers

The failure of the shippers to perform their contractual obligations under the transportation contracts could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet agreed thresholds. Vector Pipeline also has a diverse group of long-term transportation shippers, which includes various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

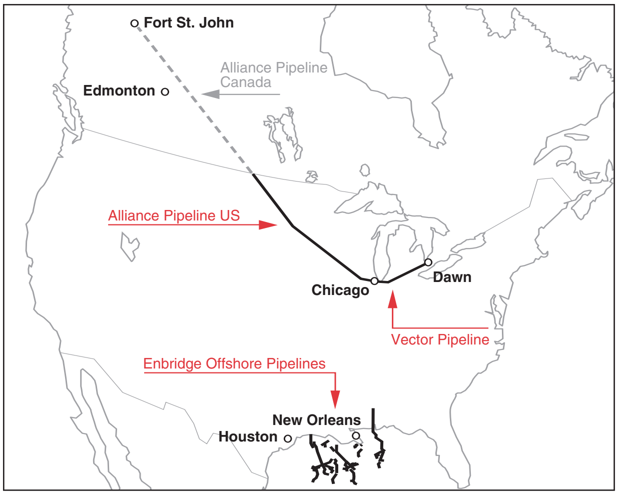
Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines, with a combined transportation capacity of approximately 3.8 bcf/d provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System. Shippers on Alliance Pipeline US have access to additional delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US's competitive position.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts for approximately 70% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts penalize early termination if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigation factors is evidenced by the increase in the utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US are regulated by the FERC which has the responsibility to ensure that rates charged are not greater than those necessary to enable the pipelines to recover costs prudently incurred and to earn a reasonable return. Under FERC regulations, the FERC, shippers and others have the opportunity to contest rates and the tariff structure.



Gas Pipelines

Enbridge Offshore Pipelines

Weather

Adverse weather, such as hurricanes, may impact EOP financial performance directly or indirectly. Direct impacts may include damage to EOP facilities resulting in lower throughput and inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and refineries that indirectly decrease throughput on EOP systems.

Competition

There is significant competition for new and existing business in the Gulf of Mexico. EOP has been able to capture key opportunities, which extends its footprint, positioning EOP to more fully utilize existing capacity. EOP serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has EOP well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. However, offshore pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of EOP's transmission pipelines are generally based on a regulated cost-of-service methodology and are subject to regulation by the FERC. These rates may be subject to challenge.

Other Risks

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

SPONSORED INVESTMENTS

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Income Fund (EIF)	**34.2**	30.0	17.6
Enbridge Energy Partners (EEP)	**21.7**	28.6	27.3
Gain on sale of assets to EIF	**–**	–	169.1
Dilution gains	**8.9**	7.6	20.3
	64.8	66.2	234.3

Business Activities

Sponsored Investments includes the Company's 10.9% ownership interest in EEP and a 41.9% equity interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

Enbridge Energy Partners

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

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner, receives incremental incentive cash distributions, which represent incentive income, on the portion of cash distributions, on a per unit basis, that exceed certain target thresholds as follows:

	Unitholders	Enbridge
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First Target – $0.59 per unit up to $0.70 per unit	85%	15%
Second Target – $0.70 per unit up to $0.99 per unit	75%	25%
Over Second Target – Cash distributions greater than $0.99 per unit	50%	50%

During 2005, EEP paid quarterly distributions of $0.925 per unit (2004 – $0.925 per unit; 2003 – $0.925 per unit). Of the $21.7 million Enbridge recognized as earnings from EEP during 2005, 64.7% (2004 – 50%; 2003 – 49%) were incentive earnings while 35.3% (2004 – 50%; 2003 – 51%) were Enbridge's share of EEP's earnings.

Enbridge Income Fund

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the Enbridge Saskatchewan System, both purchased from the Company in 2003. The Alliance Pipeline Canada is the Canadian portion of the Alliance System, described in the Gas Pipelines segment above. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in southern Saskatchewan and southwestern Manitoba connecting primarily with Enbridge Inc.'s mainline pipeline to be transported to the United States.

Enbridge receives a base annual management fee of $0.1 million for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2005, the Company received incentive fees of $2.1 million (2004 – $0.8 million, 2003 – nil). The Company is the primary beneficiary of EIF through a combination of the voting units and a preferred units investment and as such EIF is consolidated, starting January 1, 2005, under variable interest entity rules.

Results of Operations

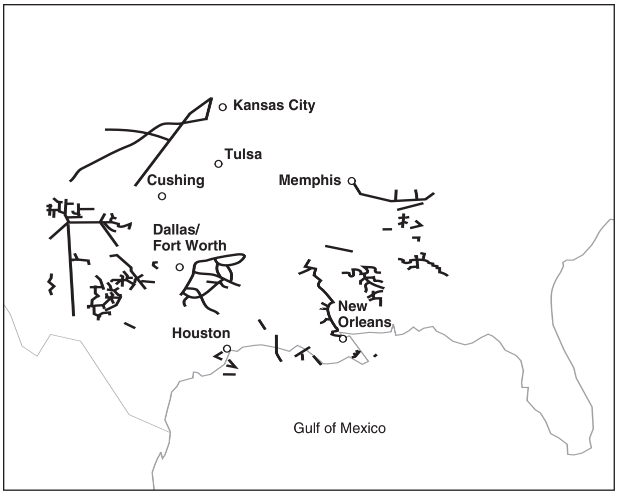
Earnings from Sponsored Investments are $64.8 million for the year ended December 31, 2005, compared with $66.2 million in 2004. EIF has increased earnings of $4.2 million due to allowance oil sales on the Saskatchewan System and collection of a notional tax in tolls on Alliance Canada. This increase is more than offset by EEP's non-cash unrealized mark-to-market losses on derivative instruments that are considered ineffective hedges for accounting purposes.

The decrease in 2004 earnings compared with 2003 stems from the gain of $169.1 million on the sale of the Company's interests in Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) to EIF in 2003.

Enbridge Income Fund

EIF earnings are $34.2 million for the year ended December 31, 2005, compared with $30.0 million for the year ended December 31, 2004. The 2005 results include higher preferred unit distributions as well as higher incentive income consistent with EIF's cash distribution increases in 2004. EIF's operating results benefited from strong performance at both Alliance Pipeline Canada and the Saskatchewan System.

Earnings for 2004 include a full year of operations whereas earnings for 2003 included only the six months from inception of EIF on June 30, 2003.



Enbridge Energy Partners – Gas Pipelines

Enbridge Energy Partners

Earnings of $21.7 million for the year ended December 31, 2005, are down from 2004 earnings of $28.6 million due to $5.0 million (net to Enbridge) of unrealized mark-to-market losses on derivative financial instruments, which do not qualify for hedge accounting treatment. While Enbridge believes the hedging strategies are sound economic hedging techniques, they do not qualify for hedge accounting and must be accounted for on a mark-to-market basis through earnings. In addition, EEP earnings have been negatively affected by lower Lakehead System volumes, a stronger Canadian dollar and a lower ownership interest offset with higher earnings from the natural gas business.

EEP's 2004 results reflected higher operating earnings, compared with 2003, partially offset by the stronger Canadian dollar, a lower ownership interest and the negative effect of a FERC decision requiring a refund to shippers on one of EEP's regulated natural gas pipelines. The higher operating earnings were from increased volumes on the main crude oil liquids pipeline system, as well as increased throughput and higher processing margins on various natural gas assets.

EEP issued partnership units in each of 2005, 2004 and 2003. Because Enbridge did not fully participate in these offerings, dilution gains resulted.

Strategy

Enbridge Energy Partners

EEP intends to grow primarily through organic growth, supplemented by opportunistic acquisitions. Specifically, EEP intends to:

- increase the utilization and productivity of its core assets to meet the supply of and demand for hydrocarbons in the markets EEP serves; and
- develop and acquire complementary energy delivery assets, particularly in the Gulf Coast region of the United States, and improve the financial performance and operating efficiency of these assets.

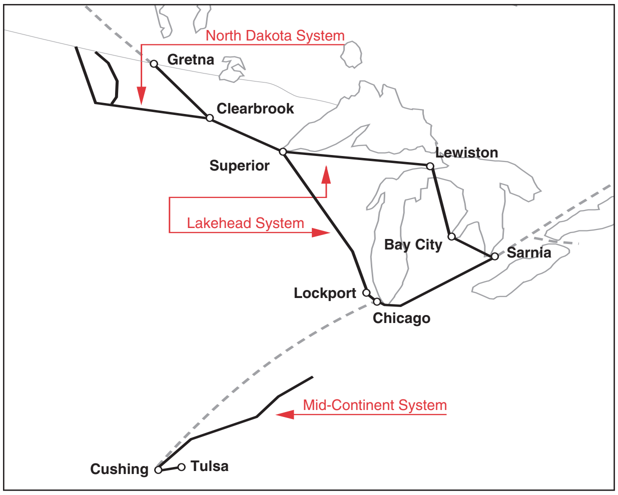
On January 30, 2006, EEP announced that it has received customer commitments to support the construction of a US$530 million expansion and extension of its East Texas natural gas system (Project Clarity). The Project will handle growing natural gas production in East Texas and will consist of a 36-inch intrastate pipeline with a capacity of approximately 700 mmcf/d, a 250 mmcf/d treating facility and a number of upstream facilities, including gathering pipelines all of which are expected to be fully operational in late 2007.

Enbridge Income Fund

Enbridge Income Fund will continue to position itself as a premier income fund in Canada with a value proposition characterized by a low risk profile with dependable but modest organic growth, long-life assets and potential for further growth through energy infrastructure acquisitions.

Business Risks

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



Enbridge Energy Partners – Liquids Pipelines

Enbridge Energy Partners

Supply and Demand

The profitability of EEP depends to a large extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of Western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada. EEP expects future increased crude oil supplies from the oil sands projects in Alberta. In addition, Enbridge's future plans to provide access to new markets in the southern United States are expected to increase demand for Western Canadian crude, resulting in increased volumes for EEP.

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

These assets are also subject to competitive pressures from third-party and producer owned gathering systems.

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP are subject to regulation by FERC or state regulators and their revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP does business.

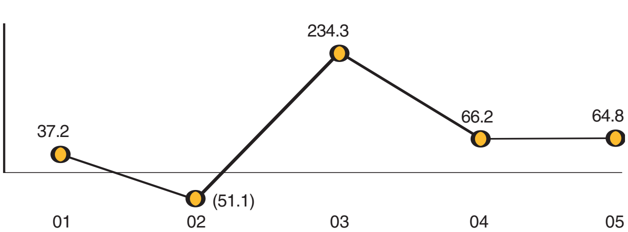
Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and natural gas liquids. Historically, these risks have been managed by using financial contracts, fixing the prices of natural gas and natural gas liquids. Certain of these contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to mark-to-market valuation changes associated with certain of these contracts.

Enbridge Income Fund

Risks for Alliance Pipeline Canada are similar to those identified for the Alliance Pipeline US in the Gas Pipelines segment.

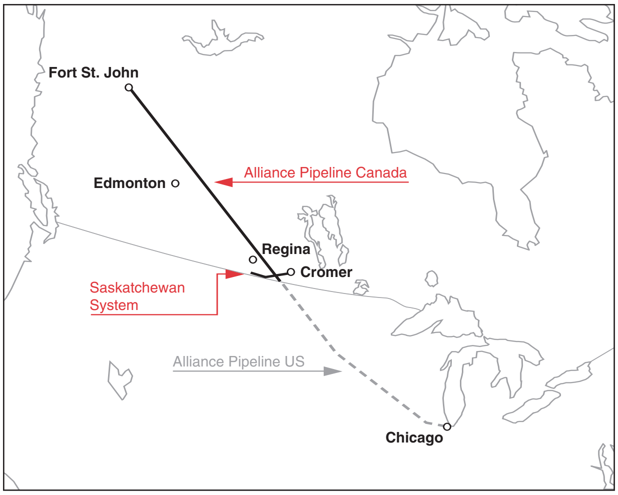
The majority of the volumes shipped on the Saskatchewan and Westspur common carrier pipeline systems, components of the Saskatchewan System, have no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls. However, there is limited pipeline competition in this area. The main competition to the pipelines is from trucking.



Sponsored Investments Earnings

(millions of Canadian dollars)

Sponsored Investments includes the Company's 10.9% ownership interest in Enbridge Energy Partners and a 41.9% equity interest in Enbridge Income Fund. In 2005, Sponsored Investment earnings were down slightly from 2004 as increased EIF earnings were more than offset by EEP's non-cash unrealized mark-to-market losses on derivative investments.



Enbridge Income Fund

EIF's liquids and natural gas pipelines are dependent upon the supply of and demand for crude oil and natural gas from Western Canada. Supply, in turn, is dependent upon a number of variables, including the level of exploration, drilling, reserves and production of crude oil and natural gas, the accessibility of Western Canadian crude oil and natural gas, the price and quality of crude oil and natural gas available from alternative Canadian and United States sources. In addition, the regulatory environments in Canada and the United States, including the continued willingness of the governments of both countries to permit the export of crude oil and natural gas from Canada to the United States on a commercially acceptable basis, could impact the supply of crude oil and natural gas.

GAS DISTRIBUTION AND SERVICES

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Gas Distribution [1]	**111.9**	133.1	103.0
Noverco [1]	**28.3**	32.3	24.2
CustomerWorks/ECS	**23.2**	20.5	16.9
Other Gas Distribution [1]	**6.7**	8.5	6.8
Enbridge Gas New Brunswick	**6.1**	3.7	4.4
Gas Services	**0.2**	(2.8)	(5.9)
Aux Sable	**5.3**	7.3	(6.9)
AltaGas Income Trust (AltaGas)	**–**	21.1	12.3
Gain on sale of investment in AltaGas	**–**	97.8	–
Impairment loss on Calmar gas plant	**–**	(8.2)	–
Other	**(2.9)**	(0.2)	(1.2)
	178.8	313.1	153.6

1 The year ended December 31, 2004 includes earnings for the 15 months ended December 31, 2004. The year ended December 31, 2003 includes earnings for the year ended September 30, 2003.

Business Activities

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

Enbridge Gas Distribution

EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.75 million customers in Central and Eastern Ontario, Southwestern Quebec, and parts of Northern New York State. EGD's operations in Ontario are regulated by the Ontario Energy Board (OEB).

Gas Distribution Rates

In November 2004, EGD received approval from the OEB for its 2005 rates, under a cost of service model. The key elements are summarized below:

Regulatory year	Requested 2006	Approved 2005	Approved 2003
Rate base *(millions of Canadian dollars)*	$3,596.2	$3,422.1	$3,155.8
Deemed common equity for regulatory purposes	35.00%	35.00%	35.00%
Rate of return on common equity	10.11%	9.57%	9.69%

The rate of return on common equity is calculated with reference to a formula approved by the OEB that incorporates the long bond yield forecast. The rate of return of 10.11% requested for 2006 was a preliminary calculation based on the forecast yield for long bonds used in the formula at the time the 2006 rate application was made. Subsequent movements in the forecast yield for long bonds have resulted in an updated rate of return on common equity of 8.74% becoming applicable for 2006.

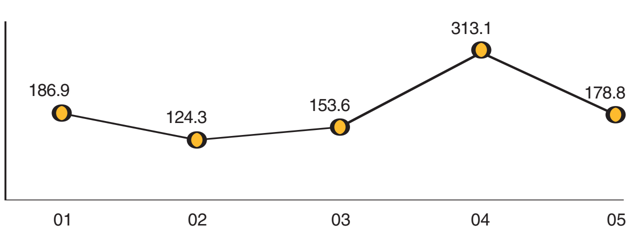
EGD's 2005 and 2003 rates were established pursuant to a cost-of-service methodology that allowed revenues to be set to recover EGD's forecast costs. For 2004, rates were set by increasing 2003 rates by 90 percent of the forecast Ontario consumer price index, resulting in an increase of 1.8 percent. The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a weather-normalized basis exceed the benchmark ROE, these excess earnings were shared on a 50/50 basis between ratepayers and the Company's shareholders. The 2004 financial results for the fifteen months ended December 31, 2004, include a reduction of $8.7 million after tax for the earnings sharing with customers.

Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, income taxes, and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in gas distribution, storage and transmission, as well as an allowance for working capital. Under the cost-of-service model, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs. EGD does not earn a profit on the price of natural gas.

The rate base is financed by EGD through a combination of debt and equity. The proportion of debt and equity, currently 65% and 35% respectively, is approved by the OEB. For the debt portion, interest expense incurred by the Company is recovered in rates. For the equity portion, the OEB sets the rate of return that EGD may recover in rates. The allowed rate of return on equity for EGD is based on the forecast yield on Canadian government long-term bonds.

Earnings from EGD are impacted to the extent that volumes sold differ from forecasted volumes. There are four key factors that affect the probability that EGD will distribute the forecast volumes. These are weather, economic conditions, gas prices and the prices of competing energy sources and the number of customers added. To the extent that these factors vary unfavourably compared with forecasts, earnings will be less than the total revenue requirements established in the ratemaking process due to lower distribution volumes.

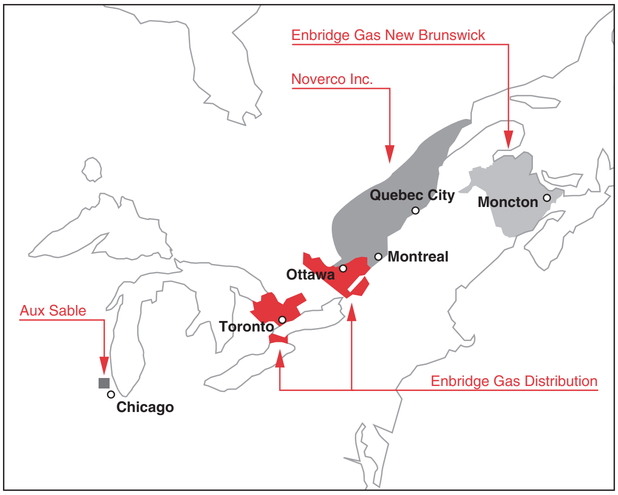
Distribution volume may also be impacted by the increased adoption of energy efficient technologies along with more efficient building construction that continues to place downward pressure on annual average consumption.



Gas Distribution and Services Earnings

(millions of Canadian dollars)

Gas Distribution and Services earnings in 2005 were down $134.3 million compared with 2004. Earnings in 2004 included 15 months of operations from the gas distribution operations as a result of the change in fiscal year end, and an after-tax gain of $97.8 million on the sale of the investment in AltaGas Income Trust.



Gas Distribution and Services

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

2006 Rate Application

On March 18, 2005, EGD filed an application with the OEB for approval of the 2006 rates, under a cost-of-service model. A final decision on this rate application is expected from the OEB during the first quarter of 2006.

In 2005, EGD added approximately 50,700 customers (15 months ended December 31, 2004 – 74,500; 12 months ended October 31, 2003 – 54,800). The increased number of customers is due primarily to the strong housing market in EGD's franchise area driven by low interest rates, urbanization and immigration patterns. EGD expects to continue to add 45,000 to 55,000 customers per year in the foreseeable future due to continued growth in the greater Toronto area. This level of customer growth would lead to continued growth of EGD's rate base. EGD serves approximately 95% of the residential homes in its franchise area and, as the price of natural gas continues to be favourable relative to competing energy sources, expects to continue this level of market penetration.

CustomerWorks/ECS

CustomerWorks/ECS includes the operations of CustomerWorks and Enbridge Commercial Services (ECS). CustomerWorks is 70% owned by Enbridge and provides customer care services, including billing, collections, and operation of call centers primarily for; EGD, Direct Energy Essential Home Services and Terasen (a gas distribution company in British Columbia). ECS owns the customer information services system that CustomerWorks uses under license to provide services to EGD.

Noverco

Enbridge owns an equity interest in Noverco through ownership of 32% of the common shares and a cost investment through ownership of preferred shares. Noverco is a holding company that owns approximately 75% of Gaz Metro Limited Partnership (Gaz Metro), a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro also has a 50% interest in TQM Pipeline, which transports natural gas in Quebec.

Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings adjustments at Enbridge. Noverco receives dividends from Enbridge but because Enbridge owns part of Noverco, a portion of the dividends Noverco receives are effectively dividends that Enbridge has paid to itself. This portion of the dividends paid reduces the book value of Enbridge's investment in Noverco.

Enbridge Gas New Brunswick

The Company owns 64% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 4,858 customers. Approximately 470 kilometres (294 miles) of distribution main has been installed with the capability of attaching approximately 20,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Aux Sable

Enbridge owns 42.7% of Aux Sable, a NGL extraction and fractionation business. Aux Sable owns and operates a plant, attached to the terminus of the Alliance System. The plant extracts NGL from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGL, or lower heat content, and to take advantage of positive commodity price spreads. The NGL, which include ethane, propane, normal butane, iso-butane and natural gasoline, are resold. Aux Sable's ability to generate earnings is dependent on the difference between the prices of the NGL and natural gas, which Aux Sable must buy to replace the NGL it extracts from the Alliance System. Starting in 2004, heat content requirements were reduced providing increased operating flexibility, largely enabling Aux Sable to operate only when it is economic.

Aux Sable has entered into a binding memorandum of agreement with BP Products North America Inc. to sell all of its NGL production to BP at its facilities near Chicago. In return, BP will pay Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified thresholds. In addition, BP will compensate Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP will supply, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and will assume responsibility for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement will be for an initial term of 20 years, commencing December 31, 2005, and may be extended by mutual agreement for 10 year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, however Aux Sable has the right to reduce such losses to avoid termination.

Gas Services

The Company's gas services business markets natural gas to optimize Enbridge's commitments on the Alliance and Vector Pipelines. It also has a growing business of providing fee for service arrangements for third parties, leveraging its marketing expertise.

Tidal Energy

Tidal Energy (Tidal) provides crude oil marketing services for the Company and its customers in a full range of crude oil types including light sweet, light and medium sours and several heavy grades and natural gas liquids. Tidal transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing Risk Management Pricing options. Tidal's business involves buying, selling and storing large quantities of crude oil at low margins. Tidal does not trade on a speculative basis and its business is tightly monitored by, and must comply with, the Company's formal risk management policies. Earnings from Tidal are included in Other.

Results of Operations

Earnings are $178.8 million for the year ended December 31, 2005, compared with $313.1 million for the year ended December 31, 2004. The 2004 earnings include 15 months of operations from the gas distribution operations as a result of the change in EGD's fiscal year end. Also included in the earnings of 2004 is the after-tax gain of $97.8 million on the sale of the investment in AltaGas Income Trust.

Reported earnings for the year ended December 31, 2003, included EGD's results for the twelve months ended September 30, 2003.

Enbridge Gas Distribution

(millions of Canadian dollars)	**2005**	2004	2003
Enbridge Gas Distribution – as reported	**111.9**	133.1	103.0
Significant non-operating factors and variances:			
Calendar year basis adjustment	**–**	(11.5)	0.8
Regulatory disallowances	**–**	–	35.2
Colder than normal weather	**–**	(21.3)	(33.9)
Unbilled revenue	**–**	–	(33.6)
Tax rate adjustments	**–**	–	51.4
	111.9	100.3	122.9

As noted above, earnings for the year ended December 31, 2004, included 15 months of earnings for Enbridge Gas Distribution, as a result of the elimination of the quarter lag basis of consolidation. Earnings for the first quarter, ended December 31, 2003, have been eliminated to adjust 2004 earnings to a calendar basis, making it comparable to 2005. The remaining EGD variance, after considering the items listed above, is the result of a higher rate base and a number of smaller positive variances across the utility.

Earnings for 2003 have also been adjusted to reflect the calendar basis, making them comparable with 2005. The 2003 regulatory disallowances related to gas costs for a long-term transportation contract, an outsourcing disallowance, as well as a $26.0 million write-down of a regulatory receivable. Unbilled revenue is the difference between amounts charged to customers based on estimated gas consumption and the actual volumes delivered in the reporting period. Starting October 1, 2003, EGD refined its process and began recording unbilled revenue on a quarterly basis using a current estimate of actual volumes delivered. In 2003, the unbilled revenue accrual was based on amounts approved by the OEB for the September 30 year-end. When the 2003 results are adjusted to reflect a calendar year, the quarter added, October 1 to December 31, 2003, has unbilled revenue recorded at the full December 31 amount. The quarter removed, October 1 to December 31, 2002, does not include the full impact of unbilled revenue because EGD was still using its previous estimation process during that period. Therefore, it is necessary to remove the effects of unbilled revenue, recorded in the quarter ended December 31, 2003, from the calendar adjustment to make 2003 comparable with 2004 and 2005.

Normal weather is the weather forecast by EGD in its annual rates application, in the Toronto area, including the impacts of both the long run and short run actual historical weather experience, more heavily weighted on the short run experience, and is subject to OEB approval. This financial measure is unique to EGD and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized factors that may be identified by other companies. Moreover, normal weather may not be comparable year-to-year given that the forecasting model weights the degree-days from the most recent years more heavily to determine the estimate. This weather-normalized adjustment method is the same as the manner in which EGD calculates degree-days for regulatory purposes.

Noverco

(millions of Canadian dollars)	**2005**	2004	2003
Noverco – as reported	**28.3**	32.3	24.2
Significant non-operating factors and variances:			
Calendar year basis adjustment	**–**	(13.6)	3.4
Dilution gains in Noverco on Gaz Metro issuances	**(7.3)**	–	(7.1)
Tax rate adjustments	**–**	–	0.7
	21.0	18.7	21.2

Noverco earnings are $2.3 million higher for the year ended December 31, 2005 compared with the year ended December 31, 2004, after considering the items listed above. The increase reflects a future income tax recovery related to the receipt of cash dividends net of an adjustment for reciprocal dividends. During the year, the Company received a $70 million cash dividend from Noverco and recorded a $50 million adjustment for reciprocal dividends paid to Noverco.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

Other Gas Distribution Operations

(millions of Canadian dollars)	**2005**	2004	2003
Other Gas Distribution Operations – as reported	**6.7**	8.5	6.8
Significant non-operating factors and variances:			
Calendar year basis adjustment	**–**	(2.1)	(0.4)
	6.7	6.4	6.4

Earnings from Other Gas Distribution Operations, after the calendar basis adjustment, are consistent for the three year period.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick earnings are $6.1 million for the year ended December 31, 2005, compared with $3.7 million for the year ended December 31, 2004. The increase is consistent with the settlement of debt through the issue of equity, resulting in a higher equity base.

Gas Services

Gas Services recorded earnings of $0.2 million for the year ended December 31, 2005, an improvement of $3.0 million from 2004. The Gas Services business includes several natural gas related businesses, including U.S. Oil acquired in January 2005.

Gas Services experienced a loss of $2.8 million for the year ended December 31, 2004, compared with a loss of $5.9 million in 2003. The improvement from 2003 reflected a continuing increase in the demand for natural gas and associated transmission services, reducing merchant capacity losses on the Alliance System and Vector Pipeline.

Aux Sable

Earnings for the year ended December 31, 2005, are $5.3 million compared with earnings of $7.3 million for the year ended December 31, 2004. The decrease is due to higher natural gas costs in 2005, which were not offset by product sales prices causing weak margins and therefore decreased production levels.

The positive earnings from Aux Sable in 2004 compared with 2003 were the result of positive fractionation margins. Enbridge's ownership interest in Aux Sable was also higher in 2004, as an additional 11.8% was acquired in April 2003 resulting in the current ownership of 42.7%. As the acquisition of the additional interest was at a discount to the book value, depreciation expense is lower on that additional interest.

AltaGas

The Company sold its investment in AltaGas in the third quarter of 2004. The earnings contribution from AltaGas in 2004 reflected a number of factors including an $8.0 million after-tax dilution gain.

Other includes higher costs in 2005, compared with 2004, related to the development of the Rabaska LNG facility.

Strategy

While EGD will continue to be under the cost-of-service model in 2006, EGD will continue to file through the cost-of-service process to ensure a just and reasonable base is in place for a 2008 incentive regulation plan. Enbridge will continue to explore new business opportunities that are complementary to the distribution business, including energy and fuel cell investments. Enbridge will pursue an industry facilitation strategy to make it easier for customers to find, install and finance natural gas appliances. Enbridge is committed to enhancing customer satisfaction by aligning service standards with customer commitment and to ensuring customers have access to a secure gas supply by pursuing new sources of natural gas and storage opportunities.

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

- developing LNG regasification projects and related pipeline infrastructure, pursuing marketing and storage opportunities that optimize existing assets,
- pursuing marketing and storage opportunities that optimize existing assets,
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets, and
- increasing the scale of the wind power business in locations near existing Enbridge infrastructure.

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

Rabaska LNG Facility

Enbridge, Gaz Metro and Gaz de France are continuing development of the previously announced Rabaska LNG terminal to be located on the St. Lawrence River in Levis, Quebec. The Levis municipal council has reversed an earlier decision opposing the project and are now fully supportive. Options for the required land have been secured and environmental filings were filed with federal and Quebec authorities in January 2006. The partners are in the process of developing definitive supply and market agreements. The project is expected to cost approximately $840 million in total.

Goreway Power Project

The Company, in partnership with Sithe Global Power, L.L.C., has been selected by the Ontario Power Authority (OPA) to enter into negotiations to develop a 880-megawatt gas-fired power generation plant in Brampton, Ontario. The new plant would provide needed electricity to the Western Greater Toronto Area. Enbridge would hold a 25% interest in the project, which would provide the Company with an entry point into the gas-fired power generation business in a geographical area already served by the Company's largest gas distribution business, EGD.

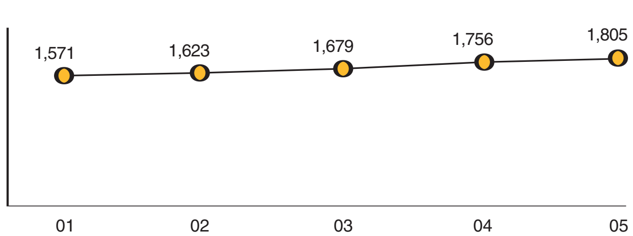
Ontario Wind Project

Enbridge will be developing 200 megawatts of wind power on the eastern shore of Lake Huron in Ontario. Construction will commence in mid-2006 and total capital expenditures are expected to be approximately $400 million. Enbridge has entered into a 20-year electricity purchase agreement with the OPA for all of the power produced by the project. Enbridge currently has ownership in three wind power projects, which generate over 70 megawatts, in total.

Capital Expenditures

In order to support continuing customer growth, expansion of EGD's network on an ongoing basis is required. In addition, as part of its 2006 rate application, EGD has requested the OEB's approval for an accelerated program to replace the remaining cast iron mains with polyethylene mains. If the OEB approves the request for the accelerated cast iron main replacement program along with certain other requested capital expenditures, total capital expenditures during 2006 will be approximately $460 million, as compared to the annual capital expenditures in recent years of between $250 million to $300 million a year.

Capital expenditures in other Gas Distribution and Services businesses, including the Ontario Wind Project, described above, are expected to be approximately $240 million in 2006.



Gas Distribution Number of Active Customers

(thousands)

Enbridge Gas Distribution continues to add between 50,000 and 60,000 new customers per year: the 2004 number reflects the 15-month period reported as part of Enbridge's change in financial reporting to eliminate consolidation of gas distribution operations on a quarter lag basis.

Enbridge Gas Distribution Legal Proceedings

Class Action Lawsuit – late payment penalties

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

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

Bloor Street Incident

EGD has been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. The maximum possible fine upon conviction on all charges would be $5.0 million in aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion has also been called, but the proceedings are stayed pending resolution of the TSSA and OHSA matters. The courts have not yet ruled upon any of the charges laid under the TSSA or the OHSA, and thus it is not possible at this time to predict or comment upon the potential outcome. The trial in respect of these charges commenced January 3, 2006. EGD does not expect the outcome of these civil actions to result in any material financial impact.

Business Risks

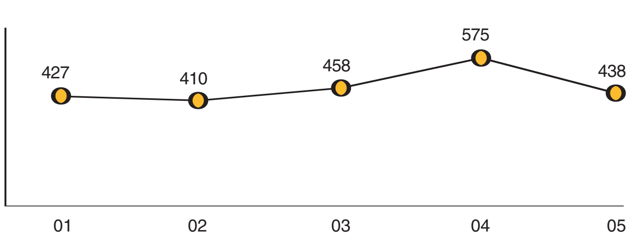
The risks identified below are specific to the Gas Distribution and Services business. General risks that affect the Company as a whole are described under Risk Management.

Enbridge Gas Distribution

The business risks inherent in the natural gas distribution industry impact the ability of EGD to realize the revenue level required to generate the allowed return on equity. These business risks include obtaining timely and adequate rate relief, accuracy in forecasting, and then realizing, natural gas distribution volumes.

Volume Risks

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



Volume of Gas Distributed

(billions of cubic feet)

Gas volumes distributed reflect the growing number of active customers and the impact each year of warmer than normal or colder than normal weather: the 2004 number reflects the 15-month period.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 78% (2004 – 77%) of total distribution volume. Weather during the year, measured in degree days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating. In 2005, degree days closely approximated those forecast, resulting in no weather related volume variance.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies along with more efficient building construction that continues to place downward pressure on annual average consumption. Average annual gas usage has declined by 1.0% per annum over the last 10 years, reflecting consistent customer conservation efforts.

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

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as, mix of sales and transportation of gas for customers, the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

Rate Relief

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

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

EGD does not profit from the price of the natural gas commodity nor is it at risk for the difference between the actual cost of gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition.

Forecasting Accuracy

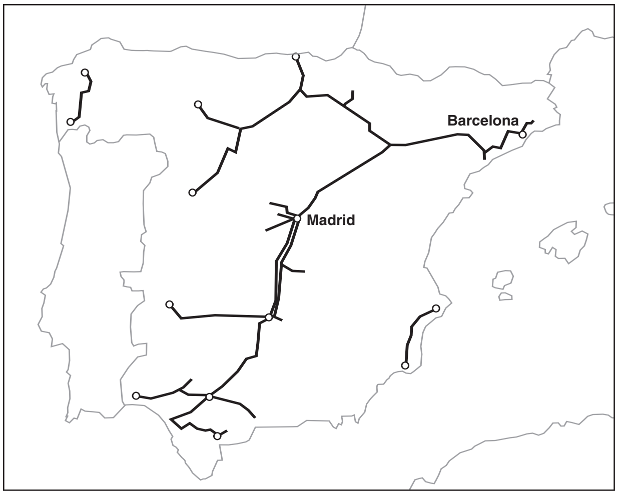
Forecasting accuracy is a risk since rates are established in advance, based on anticipated distribution volume by class of customer. Forecasts are also made for the future cost of capital including the forecast yield rate for long-term Government of Canada Bonds used in the determination of the return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

Franchise Rights

To date, the OEB has upheld the Company's exclusive right to serve all end users within its franchise area, under its franchise agreements. Similar franchise agreements are held by peer companies such as Union Gas Limited (UGL). On January 6, 2006, the OEB granted Greenfield Energy Corporation, a potential power-plant customer of UGL, the right to physically bypass UGL's distribution network within UGL's franchise area, in order to serve its own power-plant. The OEB's decision to not uphold exclusive franchise rights of a local distribution utility in Ontario is unprecedented. However, the OEB characterized this decision as transitional, and has set up a rates proceeding to assess the service requirements of gas fired generation in the province of Ontario. At the present time, the Company is unable to assess the possible future financial implications given the recentness of this decision and potential outcomes from the above rates proceeding.

Gas Services

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



Spain – CLH

Aux Sable

Earnings from Aux Sable were exposed to the effect of spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. This risk was mitigated by lower heat content requirements on downstream pipelines, which commenced in 2004, and the use of commodity hedges, which opportunistically locked in positive margins when forward markets allow.

Demand for NGL is influenced by overall weather and economic activity because NGL are used to make energy products for home and industrial heating and as feedstock for the petrochemical industry, among other things. Because Aux Sable's earnings are dependent, to a large degree, on commodity prices, earnings can be volatile. To reduce this volatility, Aux Sable entered into hedge transactions to fix the spread between natural gas and NGL prices. Starting in 2006, this risk will be eliminated by Aux Sable's contract with BP.

INTERNATIONAL

Earnings

(millions of Canadian dollars)	**2005**	2004	2003
CLH	**61.6**	48.6	46.3
OCENSA/CITCol	**32.8**	33.0	32.3
Other	**(7.0)**	(8.0)	(6.3)
	87.4	73.6	72.3

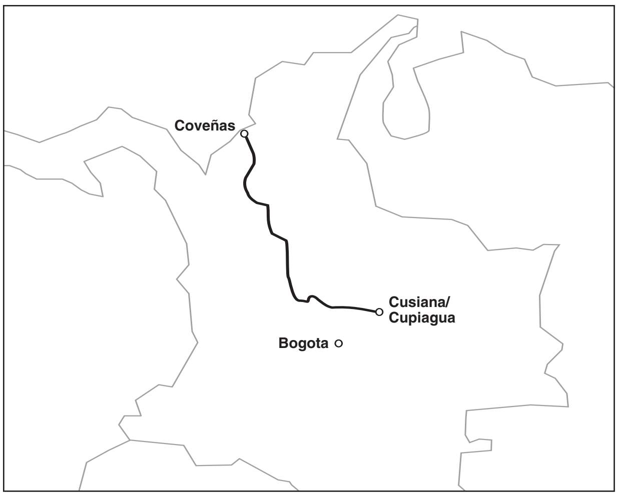
Business Activities

International includes earnings from the Company's 25% interest in Compañia Logistica de Hidrocarburos (CLH), Spain's largest refined products transportation and storage business, and OCENSA, a crude oil pipeline in Colombia. Earnings also include fees earned from technology and consulting services provided by Enbridge Technology Inc.

CLH

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

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access non-discriminatory basis. The system consists of over 3,400 kilometres of pipelines and 39 storage facilities located throughout the country. CLH provides product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships. CLH also offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition, allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, the aviation fuel business will continue. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where most of Spain's crude oil and refined products are imported.



Colombia – OCENSA

Earnings from CLH are directly impacted by the demand for refined products including diesel and other fuels for transportation purposes. Economic growth in Spain over the last decade has been one of the highest in the European Union, which has led to increasing demand for energy, including refined products. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH plans to expand its system over the next several years in order to meet the continued growth expected in this region. This expansion, which includes looping of both the northern and southern main lines, will be constructed in phases to match the expected growth in volumes.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, a cost investment on which the Company earns a fixed return. OCENSA is of one of two crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages it and earns a fee for this service, which includes incentive earnings for operating performance.

Results of Operations

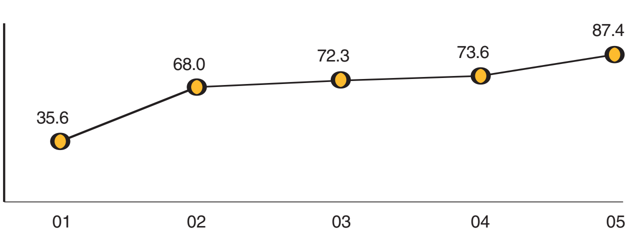
Earnings for the year ended December 31, 2005, are $87.4 million compared with $73.6 million for the year ended December 31, 2004. The increase results primarily from a $7.6 million gain on the sale of land in CLH. Operating results at CLH are also improved due to higher volumes and increased average tariffs and storage revenues.

In 2004, increased earnings of $1.3 million compared with 2003 were due to stronger results from CLH and from CITCol, operator of the OCENSA pipeline, which exceeded certain operational performance targets resulting in additional incentive income. Operating results from CLH reflected increased volumes in 2004 compared with 2003 due to greater demand for refined products throughout Spain, lower operating costs and the translation impact of the stronger Euro.

Other costs include other administration and business development costs.

Strategy

Enbridge plans to increase its business development activity in Europe and Latin America. In Europe, Enbridge will seek opportunities to acquire assets or develop greenfield projects that facilitate expected supply flow through eastern European countries to satisfy growing western European demand. In Colombia, where the Company has substantial expertise, Enbridge will focus on acquiring additional assets.



International Earnings
(millions of Canadian dollars)

International earnings include earnings from the Company's interests in CLH in Spain and OCENSA in Colombia. Earnings in 2005 increased primarily because of improved operating results at CLH and a $7.6 million gain on the sale of land in CLH.

Business Risks

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

CORPORATE

(millions of Canadian dollars)	**2005**	2004	2003
Corporate	**(63.9)**	(81.3)	(76.6)

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

Corporate costs are $63.9 million for the year ended December 31, 2005, compared with $81.3 million for the year ended December 31, 2004. Corporate costs are lower in 2005 reflecting lower interest expense due to lower rates. Also, business development costs were higher in 2004.

The 2004 corporate costs include a higher expense for stock-based compensation, compared with 2003, and increased business development activity, partially offset with lower interest expense.

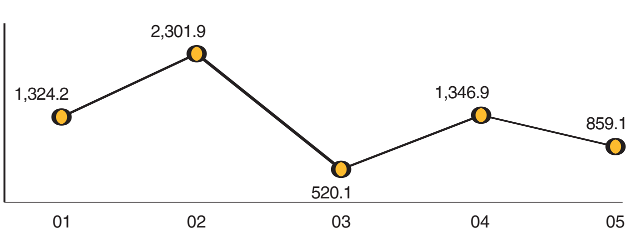
LIQUIDITY AND CAPITAL RESOURCES

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities, which totaled $3,454.8 million on December 31, 2005, and access to capital markets in Canada and the United States for the issuance of long-term debt, equity, or other securities are expected to be sufficient to satisfy liquidity and capital expenditure requirements.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2005, including short-term borrowings, but excluding non-recourse short and long-term debt, was 64.5%, compared with 65.1% at the end of 2004. The improved debt to capitalization ratio reflects the Company's continuing commitment to maintaining a strong balance sheet.

The Company's current liabilities routinely exceed current assets. This deficit is funded through cash from operations, which are typically about double the balance of the deficit in a given year. For example, at the end of 2003, the working capital deficit was $270.5 million. During 2004, operations generated $886.7 million cash which easily funded the deficit. The Company expects this trend to continue.

The Company's cash balance at the end of the year includes $16.4 million (2004 – $6.0 million; 2003 – $18.7 million) held in trust in joint ventures, pursuant to finance agreements within the joint ventures.



Capital Expenditures, Investments and Acquisitions
(millions of Canadian dollars)

The 2005 total for capital expenditures, investments and acquisitions reflects regular additions to property, plant and equipment, primarily related to the gas distribution utility; expenditures on capital projects such as the reversal of the Spearhead Pipeline and the Ontario Wind Power Project; and the acquisition of additional interests in Enbridge Offshore Pipelines.

Operating Activities

Cash from operating activities increased to $903.5 million for the year ended December 31, 2005, from $886.7 million for the year ended December 31, 2004, and $368.5 million for the year ended December 31, 2003.

(millions of Canadian dollars)	**2005**	2004	2003
Earnings net of non-cash items	**1,300.9**	1,027.8	938.3
Changes in operating assets and liabilities	**(397.4)**	(141.1)	(569.8)
Cash Provided by Operating Activities	**903.5**	886.7	368.5

Cash provided by earnings net of non-cash items, was $1,300.9 million for the year ended December 31, 2005, compared with $1,027.8 million and $938.3 million for 2004 and 2003, respectively. This $273.1 million increase in cash from 2004 reflects special dividends from Noverco, cash generated by Enbridge Offshore Pipelines, acquired on December 31, 2004, and increased earnings from EGD.

In 2004 cash from earnings net of non-cash items reflected increased contributions from the Enbridge System, due to the Terrace Phase III expansion placed into service on April 1, 2003, from EGD, due to increased rates in 2004, and from Aux Sable, due to improved fractionation margins in 2004 compared with 2003.

Changes in operating assets and liabilities were $258.7 million lower in 2005 compared with 2004. The majority of this change is in EGD where higher commodity prices increased accounts receivable and inventory.

The variance in changes in operating assets and liabilities from 2003 to 2004 was due to the draw down of gas in storage in EGD from September 30, 2003, (the prior year end) to December 31, 2004, (the new year end). Gas in storage is typically lower at the end of December as winter demand has drawn down some of the supply.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2006.

Investing Activities

Cash used for investing activities for the year ended December 31, 2005, was $833.0 million compared with $999.7 million in 2004. In 2005, the majority of cash spent on investing was for additions to property, plant and equipment, primarily in EGD. The increase in additions to property, plant and equipment in 2005, compared with 2004, is due to increased expenditures on capital projects, such as the reversal of the Spearhead Pipeline and the Ontario Wind Power Project.

In 2005, the Company made minor acquisitions throughout the year of $88.6 million whereas, in 2004, $833.9 million was used for acquisitions including Enbridge Offshore Pipelines, acquired for $743.4 million (net of cash acquired) and other minor acquisitions. Cash proceeds from the sale of the investment in AltaGas partially offset the use of cash for acquisitions in 2004.

Also in 2005, the Company made contingent payments to the former owners of the Company's 25% interest in CLH because CLH met cumulative volume targets. These payments make up the majority of the 2005 expenditure on long-term investments. In 2004, the Company also made smaller contingent payments to the former owners of the 25% interest in CLH.

In 2003, investing activities provided $259.5 million primarily as a result of the proceeds received on the sale of assets to EIF. Also, 2003 reflected the repayment by EEP of short-term loans from the Company. Additions to property, plant and equipment were primarily related to EGD.

Financing Activities

In 2005, financing activities used cash of $22.1 million compared with a source of $114.4 million in 2004.

During 2005, the Company issued $1,020.1 million new long-term debt in the form of medium-term notes and senior notes. This new debt replaced higher interest rate medium-term notes, which matured during 2005, and short-term debt, primarily commercial paper. The repayment of short-term debt was partially offset by an increase in short-term borrowings at EGD. EGD uses short-term borrowings to finance working capital, which was higher at the end of 2005 due to increased commodity prices.

Dividends on common shares have increased again in 2005 due to an increased number of common shares outstanding and a higher dividend rate.

In 2004, cash was generated through a net issuance of debt of $788.0 million, partially offset by the payment of dividends. The Company also repaid $350.0 million of preferred securities at the end of 2004. Financing activity in 2003 included the payment of dividends and a net reduction in debt through utilization of the cash proceeds from the sale of assets to EIF.

Expected Capital Expenditures

The numerous potential organic growth projects and other growth initiatives described in the business unit sections will require capital funding. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $1,130 million during 2006 on capital projects. The Company expects to finance these expenditures through cash from operating activities and additional debt, if required.

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

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

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt	6,662.5	400.0	788.4	950.0	4,524.1
Non-recourse long-term debt	1,563.0	66.7	155.7	244.5	1,096.1
Capital and operating leases	85.0	5.1	10.3	11.0	58.6
Long-term contracts	822.5	190.9	217.0	196.4	218.2
Total Contractual Obligations	9,133.0	662.7	1,171.4	1,401.9	5,897.0

RISK MANAGEMENT

The Company's business activities are subject to both financial and operational risks. The Company has formal risk management policies and risk management systems designed to mitigate these risks.

Market Price Risk

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

The Market Price Risk metric utilized within that policy is Earnings at Risk. It is an objective, statistically derived risk metric that measures the maximum earnings loss that could result from adverse market price movements over a specified time horizon within a pre-determined level of statistical confidence, under normal market conditions.

The Company uses derivative financial instruments to manage its exposures to within these policy limits. The following summarizes the types of risks to which the Company is exposed and the hedging programs implemented:

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and Euro denominated investments, where both carrying values and earnings are subject to foreign exchange risk. Furthermore, the Company is exposed to the economic risk on the conversion of the foreign currency denominated cash flows. The Company has a hedging policy to eliminate 50% to 70% of the long-term economic exposure related to its foreign currency denominated cash flows. It will also hedge shorter term anticipated foreign currency capital expenditures. The Company hedges certain of its foreign currency denominated net equity investments with the use of cross currency swaps, par forward contracts, and foreign currency denominated debt. The return of capital on the cost accounted for investment in OCENSA also is hedged with cross currency swaps.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that it stays within its Board of Directors approved policy limit band of 15% to 25% floating rate debt within the consolidated portfolio. Fixed to floating swaps are also used from time to time to manage this position and optimize the Company's debt portfolio. The Company is also exposed to fluctuations in interest rates on anticipated fixed rate debt issuances. Also, the Company enters into interest rate derivatives to hedge a portion of the interest cost of future debt issues related to specific capital projects.

Commodity Price Risk

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

As a result of the Company's ownership interest in Aux Sable, it is exposed to the price differential between natural gas and NGL. This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of natural gas and NGL are fixed with swaps, or capped or collared with options. Starting in 2006, Aux Sable's contract with BP will eliminate this risk.

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

Natural Gas Supply Management

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

Fair Values of Derivative Instruments

The following table summarizes the financial instruments outstanding at year end for the purposes of mitigating the risks as described above. Amounts shown in the table below under Fair Value Receivable/(Payable) represent unrecognized gains/(losses) associated with these instruments.

(millions of Canadian dollars unless otherwise noted)

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

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $91.0 million (2004 – $214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2007. These instruments are recorded at fair value and have a fair value payable of $14.3 million as at December 31, 2005 (2004 – $28.8 million).

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

Credit risk on derivative financial instruments amounted to $351.8 million as at December 31, 2005 (2004 – $211.2 million) with no significant concentration with any single counterparty.

Fair Values of Other Financial Instruments

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

Total Debt

(millions of Canadian dollars)

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

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

Operating Risks

Environmental, Health and Safety Risk

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

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other risks involved in operating a comprehensive pipeline system include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to keep on hand adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company's pipelines, thereby impacting earnings. The Company has an extensive program to manage system integrity, which includes the development and use of predictive and detective in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks.

Regulation

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Rate Regulation

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

The recognition of these items in the Company's financial statements depends on its expectation of the future actions of the regulatory authorities. For example, some of the Company's rate-regulated businesses do not record future income taxes because the regulatory authorities prescribe the use of the taxes payable method for rate-making purposes and there is reasonable expectation that future income taxes will be recovered as they become payable.

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

The Company's operations are regulated under three main regulatory regimes. Enbridge System negotiates tolls with its shippers under either the ITS or for specific expansions and these agreements are approved by the NEB. EGD files a rate application with the OEB, for its approval. Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines have negotiated transportation services contracts with shippers that incorporate a FERC-approved toll and tariff structure. Descriptions of each of these regulatory regimes, including how tolls and rates are set, how costs are recovered, and how returns are calculated are included in the sections describing each of these businesses.

In 2005, the Company adopted the new accounting guideline, *Disclosure by Entities Subject to Rate Regulation.* This guideline requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the entity's financial statements.

Revenue Recognition

Generally, revenues are recorded when products have been delivered or services have been performed. Certain of the Liquids Pipelines, Gas Pipelines and gas distribution operations within Gas Distribution and Services are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts. For rate-regulated operations, revenue is recognized in a manner that is consistent with the underlying rate agreements as approved by the regulatory authority.

The Company has entered into a long-term (30 year) take or pay contract with a shipper on the Athabasca System and revenues are recorded based on the contractual terms rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning rate of return on equity, based on an assumed debt/equity ratio and level of operating costs of providing service to the shipper on the pipeline. The committed volumes on the pipeline and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate the Company for the debt and equity returns, as well as the cost of providing service. The Company is recording a receivable in these years. This ensures that the revenue recognized each period is in accordance with the underpinning return. This receivable is contractually guaranteed from the shipper and will be collected in the later years of the contract.

The recording of revenues under the terms of approved regulatory agreements of the Enbridge System may also not necessarily match the cash tolls. The agreements, and all their terms and conditions, are subject to the review and approval by the pipeline's regulator, the NEB. During their terms, the agreements govern both current and future shippers on the pipeline. The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements and other contractual arrangements with customers.

Revenues are recognized based on these agreements' definitions of an allowed revenue requirement and are generally not impacted by the level of cash tolls collected. This basis may affect the timing of recognition of revenues from that otherwise expected under generally accepted accounting principles for companies that are not rate-regulated.

Tolls are calculated in accordance with the agreements which stipulate that tolls are to be established each year based on capacity as per the various agreements and/or the allowed revenue requirement. Where actual volumes on the pipeline fall short of agreed capacity and Enbridge is unable to collect its annual revenue requirement, such deficiency is rolled into the subsequent year's tolls for collection from toll payers at that time and a receivable is recognized.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Certain amounts are deferred for recovery with the approval of the regulator and are not included in revenues or expenses that would be recognized in the income statement, absent the actions of the regulator. The regulator, through the rate-making process, allows certain variances between approved and actual expenses or income to be recovered from customers in future periods. The deferred amounts are not included in the calculation of rates to be billed to customers. While there are numerous deferral accounts approved by the regulator, the largest of these typically is the difference between the approved and actual cost of gas, which is not included in the cost of service used to determine rates, and therefore not included in revenues. The recovery of this difference is recognized on the statement of financial position, at the formal direction of the regulator, with no impact on revenues or expenses in the income statement. EGD has no exposure to the cost of gas, as it is a flow through cost that is borne directly by the ratepayer.

CHANGES IN ACCOUNTING POLICIES

Consolidation of Variable Interest Entities

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

Financial Instruments, Hedging Relationships and OCI

New accounting standards will be in effect for fiscal years beginning on or after October 1, 2006, for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

EITF 04-5 – Partnership Consolidation

In June 2005, the U.S. Emerging Issues Task Force (EITF) reached a consensus on EITF issue 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (EITF 04-5), addressing when a general partner, or general partners as a group, control and should therefore, consolidate a limited partnership. Under EITF 04-5, a sole general partner is presumed to control a limited partnership when certain conditions are met. As a result, for the first reporting period beginning after December 15, 2005, it is expected that the Company will be required to include the accounts of Enbridge Energy Partners, L.P. for U.S. GAAP purposes.

Enbridge continues to equity account for its interest in EEP under Canadian GAAP.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in the rules of the Securities and Exchange Commission and the Canadian Securities Administrators) and concluded that the Company's disclosure controls and procedures were effective as of December 31, 2005, and in respect of the 2005 year end reporting period.

QUARTERLY FINANCIAL INFORMATION[1]

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

2005	First	Second	Third	Fourth	Total
Revenue	**2,555.8**	**1,527.4**	**1,657.1**	**2,712.8**	**8,453.1**
Earnings applicable to common shareholders	**220.6**	**93.6**	**67.8**	**174.0**	**556.0**
Earnings per common share	**0.66**	**0.27**	**0.20**	**0.52**	**1.65**
Diluted earnings per common share	**0.65**	**0.27**	**0.20**	**0.51**	**1.63**
Dividends per common share	**0.2500**	**0.2500**	**0.2500**	**0.2875**	**1.0375**

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

2004	First	Second	Third	Fourth	Total
Revenue	1,709.8	2,158.8	1,615.6	2,323.6	7,807.8
Earnings applicable to common shareholders	112.4	248.4	179.7	104.8	645.3
Earnings per common share	0.34	0.74	0.54	0.31	1.93
Diluted earnings per common share	0.34	0.73	0.54	0.30	1.91
Dividends per common share	0.22875	0.22875	0.22875	0.22875	0.9150

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

Quarterly operating revenue fluctuates primarily due to the seasonality of the Company's gas distribution business. Prior to October 1, 2004, this business had a September 30 year end, which resulted in consolidation by the Company on a quarter lag basis. Therefore, peak revenues were recorded in the Company's second quarter, which represented Enbridge Gas Distribution's winter months. Starting in October 2004, EGD has changed to a December 31 year end and, as a result, the Company's consolidated fourth quarter results for 2004 include the results of EGD for the six months ended December 31, 2004.

Effective October 1, 2004, EGD's seasonal rates were replaced with a uniform annual rate. The impact of this change has resulted in lower earnings in the winter months (fourth and first quarters), offset by higher earnings in the summer months (second and third quarters), causing a shift in earnings between quarters but no earnings impact on a 12 consecutive month basis.

The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second quarter of 2004. Significant items that impacted 2005 and 2004 quarterly earnings are as follows:

- Fourth quarter earnings in 2005 include a gain of $7.6 million on the sale of land in CLH and a dilution gain of $4.3 million in EEP.
- Third quarter earnings in 2005 were negatively impacted by Hurricanes Katrina and Rita and by non-cash losses on the fair value of derivatives in EEP.
- First quarter earnings in 2005 include dilution gains in EEP and within Noverco totaling $11.9 million.
- Fourth quarter earnings in 2004 include the additional "fifth quarter" for EGD and other gas distribution businesses that account for an increase of $57.2 million. This was partially offset by an impairment loss of $8.2 million on the Calmar gas plant.
- Third quarter earnings in 2004 include a $97.8 million gain on the sale of the Company's investment in AltaGas offset by the remaining reversal of $25.6 million related to unbilled revenue.
- Second quarter earnings in 2004 reflect the $9.4 million partial reversal of the $35.0 million of unbilled revenue recorded in the first quarter of 2004 and a dilution gain of $8.0 million related to AltaGas.
- First quarter earnings in 2004 reflect a $47.6 million charge to earnings resulting from an increase in the Ontario tax rate and corresponding revaluation of future income taxes, as well as an increase of $35.0 million for unbilled revenue, consistent with a change in the estimation process in 2004, both within EGD.

FOURTH QUARTER 2005 HIGHLIGHTS

Fourth quarter earnings for 2005 are $174.0 million, compared with $104.8 million in 2004. The increase in earnings reflects a higher contribution from the gas distribution utility. Although the prior year quarter includes six months of earnings for the gas distribution utilities, the additional quarter, July 1 to September 30, 2004, is a summer loss quarter and reduced earnings in the fourth quarter of 2004. Also, in the fourth quarter of 2004, an impairment loss of $8.2 million was recognized on the Calmar gas plant.

SUPPLEMENTARY INFORMATION

Outstanding Share Data	Number of units outstanding
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	349,533,852
Total issued and outstanding stock options (6,164,141 vested)	10,994,291

Outstanding share data information is provided as at January 23, 2006.

RELATED PARTY TRANSACTIONS

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

(millions of Canadian dollars)

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

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

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable; where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates. Prices are determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

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

Dated February 1, 2006

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

Management's Report

To the Shareholders of Enbridge Inc.

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

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

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil 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 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
February 1, 2006

Stephen J. Wuori
Group Vice President & Chief Financial Officer

Auditors' Report

To the Shareholders of Enbridge Inc.

We have audited the consolidated statements of financial position of Enbridge Inc. as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the Company'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, 2005 and 2004 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
February 1, 2006

Chartered Accountants

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

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Corporation's financial statements, such as the change for the consolidation of variable interest entities described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 1, 2006 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
February 1, 2006

Chartered Accountants

Consolidated Statements of Earnings

(millions of Canadian dollars, except per share amounts)

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

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

Consolidated Statements of Retained Earnings

(millions of Canadian dollars, except per share amounts)

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

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

Consolidated Statements of Cash Flows

(millions of Canadian dollars)

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

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

Consolidated Statements of Financial Position

(millions of Canadian dollars)

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

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

Approved by the Board:

David A. Arledge
Chair

Robert W. Martin
Director

Notes to the Consolidated Financial Statements

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

Liquids Pipelines

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

Gas Pipelines

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

Sponsored Investments

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

Gas Distribution and Services

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

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

International

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

1. SUMMARY 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 26. Amounts are stated in Canadian dollars unless otherwise noted.

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

Basis of Presentation

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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

Regulation

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

Revenue Recognition

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

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

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

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

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

Income Taxes

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

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

Foreign Currency Translation

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

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

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

Cash and Cash Equivalents

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

Inventory

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

Property, Plant and Equipment

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

Intangibles

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

Goodwill

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

Asset Retirement Obligations

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

For certain of the Company's assets it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management expects all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods and therefore any liability recorded would be offset by an asset.

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

Deferred Amounts and Other Assets

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

Derivative Financial Instruments

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

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

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

Post-Employment Benefits

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

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

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

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

Stock Based Compensation

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

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

Comparative Amounts

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

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

2. CHANGES IN ACCOUNTING POLICIES

New Accounting Standards

Financial Instruments, Hedging Relationships and Other Comprehensive Income

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

Consolidation of Variable Interest Entities

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

2. CHANGES IN ACCOUNTING POLICIES (continued)

Statement of Financial Position

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

Statement of Earnings

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

Statement of Cash Flows

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

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

General Information on Rate Regulation and its Economic Effects

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

Enbridge System

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

Athabasca Pipeline

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

Vector Pipeline

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

Alliance Pipeline

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

Enbridge Gas Distribution Inc.

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

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in gas distribution, storage and transmission and an allowance for working capital. Under cost of service, it is the responsibility of EGD to demonstrate to the OEB the prudence of the costs it has incurred. For 2005, EGD's approved rate of return on the rate base was 8.10% after tax, and the approved rate of return on common equity was 9.57% after tax based on a 35% deemed common equity for regulatory purposes.

Enbridge Gas New Brunswick

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

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (continued)

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

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

Financial Statement Effects

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

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

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

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

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

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

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

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

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

5 *The PUB has approved a regulatory deferral account to capture the difference between EGNB's distribution revenues and its cost of service during the development period. The regulatory deferral account balance is to be amortized over a recovery period as approved by the PUB commencing at the end of the development period, currently expected in 2010. In a decision rendered in January 2005, the PUB has indicated that the recovery period would end no sooner than December 31, 2040.*

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

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

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

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

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

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

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

Other Items Affected by Rate Regulation

Future Income Taxes

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

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

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

AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC for rate-regulated entities includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, GAAP would permit the capitalization of only the interest component. Therefore, the set up of the equity component as a capitalized asset and the corresponding earnings recognized during the construction phase would not be recognized nor would the subsequent depreciation of the capitalized equity component. It is not possible to make a reasonable estimate of the carrying value of the equity component of AFUDC under the pool method of depreciation, prescribed by certain regulators. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as a pool of assets.

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

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (continued)

Operating Cost Capitalization

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

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

Pension Plans

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

Post-Employment Benefits Other than Pensions

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

4. SEGMENTED INFORMATION

Year ended December 31, 2005

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

Year ended December 31, 2004 (millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services[2]	International	Corporate[1]	Consolidated
Revenues	872.7	271.7	–	6,631.1	32.3	–	7,807.8
Commodity costs	–	–	–	(5,184.3)	–	–	(5,184.3)
Operating and administrative	(310.1)	(55.1)	–	(577.0)	(38.6)	(34.2)	(1,015.0)
Depreciation and amortization[3]	(145.4)	(65.7)	–	(308.4)	(1.9)	(3.6)	(525.0)
	417.2	150.9	–	561.4	(8.2)	(37.8)	1,083.5
Investment and other income	1.8	0.8	112.2	50.6	81.5	14.8	261.7
Gain on sale of investment	–	–	–	121.5	–	–	121.5
Interest and preferred share dividends	(101.4)	(65.6)	–	(211.1)	(0.2)	(153.9)	(532.2)
Income taxes	(97.7)	(32.3)	(46.0)	(209.3)	0.5	95.6	(289.2)
Earnings applicable to common shareholders	219.9	53.8	66.2	313.1	73.6	(81.3)	645.3

Year ended December 31, 2003 (millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services[5]	International	Corporate[1]	Consolidated
Revenues	821.5	222.1	–	4,659.1	26.2	0.1	5,729.0
Commodity costs	–	–	–	(3,593.8)	–	–	(3,593.8)
Operating and administrative	(288.8)	(41.2)	–	(415.9)	(30.5)	(24.4)	(800.8)
Depreciation and amortization	(142.6)	(56.7)	–	(237.6)	(2.0)	(4.1)	(443.0)
	390.1	124.2	–	411.8	(6.3)	(28.4)	891.4
Investment and other income	3.4	36.6	113.1	19.8	78.1	(42.8)	208.2
Gain on sale of assets	–	–	239.9	–	–	–	239.9
Interest and preferred share dividends	(102.1)	(58.7)	–	(162.2)	(0.5)	(176.2)	(499.7)
Income taxes	(77.9)	(32.0)	(118.7)	(115.8)	1.0	170.8	(172.6)
Earnings applicable to common shareholders	213.5	70.1	234.3	153.6	72.3	(76.6)	667.2

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

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

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

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

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

Total Assets

(millions of dollars)

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

4. SEGMENTED INFORMATION (continued)

Additions to Property, Plant and Equipment

(millions of dollars)

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

Geographic Information

Revenues[1]

(millions of dollars)

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

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

Property, Plant and Equipment

(millions of dollars)

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

5. DISPOSITIONS

AltaGas Income Trust (AltaGas)

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

Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) Inc.

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

6. ACQUISITIONS

Enbridge Offshore System

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

Spearhead Pipelines

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

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

Other

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

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

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

7. PROPERTY PLANT AND EQUIPMENT

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

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

8. JOINT VENTURES

Enbridge has joint venture interests in the following entities:

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

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

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

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

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

9. LONG-TERM INVESTMENTS

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

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

The Partnership

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

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

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

Enbridge Income Fund

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

At the request of the Company, the ECT preferred units will be repurchased for cancellation in certain specified circumstances by ECT with a repurchase price per ECT preferred unit based on the net issue price realized from the sale (or that could be realized from the sale) of an ordinary trust unit to the public. The ECT preferred units have no voting rights and mature on June 30, 2033 at which time ECT is obligated to redeem all of the outstanding ECT preferred units for $10.00 per unit. The economic terms of these units are similar to those of ordinary common units. As such, the approximate fair value of these preferred units, valued at the December 31, 2005 closing price of $14.48 per ordinary trust unit (2004 – $13.94), is $550.6 million (2004 – $530.1 million).

Noverco

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

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

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

CLH

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

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

OCENSA Pipeline

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

Income from Equity Investments

(millions of dollars)

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

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

10. DEFERRED AMOUNTS AND OTHER ASSETS

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

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

11. INTANGIBLE ASSETS

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

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

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

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

12. GOODWILL

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

13. DEBT

(millions of dollars)

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

1 Primarily commercial paper borrowings.
2 Primarily commercial paper borrowings. Includes US$256.9 million (2004 – US$585.0 million).

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

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

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

Interest Expense

(millions of dollars)

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

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

13. DEBT (continued)

Credit Facilities

(millions of dollars)

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

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

14. NON-RECOURSE DEBT

(millions of dollars)

December 31,	**2005**	2004
Gas Pipelines		
Credit Facilities of Alliance Pipeline US (US$7.7 million, 2004 – US$8.9 million)	**8.9**	10.6
Senior Notes of Alliance Pipeline US		
7.770% due 2015 (US$128.8 million, 2004 – US$134.7 million)	**150.1**	162.1
6.996% due 2019 (US$131.8 million, 2004 – US$143.2 million)	**153.7**	172.3
7.877% due 2025 (US$100.0 million, 2004 – US$100.0 million)	**116.6**	120.4
4.591% due 2025 (US$134.5 million, 2004 – US$140.6 million)	**156.8**	169.3
Capital leases obligations	**–**	0.8
Gas Distribution and Services		
Term debt of Aux Sable (US$ 4.2 million)	**4.9**	–
Capital leases obligations	**56.9**	59.9
Sponsored Investments		
Credit Facility of Enbridge Income Fund	**11.0**	–
Credit Facility of Alliance Pipeline Canada	**24.1**	–
Medium Term Notes of Enbridge Income Fund		
4.19% due 2009	**100.0**	–
5.25% due 2014	**90.0**	–
Senior Notes of Alliance Pipeline Canada		
7.230% due 2015	**126.5**	–
7.181% due 2023	**186.7**	–
7.217% due 2025	**149.2**	–
6.765% due 2025	**178.8**	–
5.546% due 2023	**120.4**	
Fair value increment on long-term debt acquired	**53.5**	
	1,688.1	695.4
Current Maturities	**(68.2)**	(30.2)
	1,619.9	665.2

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

Alliance Pipeline US

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

Aux Sable

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

Enbridge Income Fund

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

The Senior Notes may be redeemed by Alliance Pipeline Canada at any time at a price equal to the greater of (i) the applicable Government of Canada yield price plus a premium and (ii) par, together with accrued interest. Alliance Pipeline Canada may be required to redeem the Senior Notes, in whole or in part, from proceeds received under insurance claims or other claims for damages if the proceeds are not applied to repair or rebuild the Alliance pipeline system.

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

15. NON-CONTROLLING INTERESTS

(millions of dollars)

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

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

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

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

16. SHARE CAPITAL

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

Common Shares

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

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

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

Preferred Shares

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

Earnings Per Common Share

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

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

(number of common shares in millions)

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

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

Stock Split

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

Dividend Reinvestment and Share Purchase Plan

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

Shareholder Rights Plan

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

17. STOCK OPTION AND STOCK UNIT PLANS

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

Fixed Stock Options

Key employees are granted options to purchase common shares that are exercisable at the market price of the common shares at the date the options are granted. Generally, options vest in equal annual installments over a four-year period and expire ten years after the issue date. Outstanding stock options expire over a period ending no later than June 16, 2015. Compensation expense recorded for the year ended December 31, 2005, for fixed stock options is $5.5 million (2004 – $3.7 million) and is included in operating and administrative expenses.

Outstanding Fixed Stock Options

(options in thousands; exercise price in dollars)

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

17. STOCK OPTION AND STOCK UNIT PLANS (continued)

Fixed Stock Option Characteristics

(options in thousands; exercise price in dollars)

December 31, 2005	Options Outstanding			Options Vested	
Exercise Price Range	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
10.00-14.99	**1,051**	**3.73**	**12.88**	**1,051**	**12.88**
15.00-19.99	**2,034**	**4.28**	**18.16**	**2,034**	**18.16**
20.00-24.99	**3,225**	**6.65**	**21.29**	**1,793**	**21.39**
25.00-29.99	**1,638**	**8.11**	**25.74**	**370**	**25.74**
30.00-33.55	**1,486**	**9.10**	**31.70**	**–**	**–**
	9,434			**5,248**	

Performance-based Options

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

Outstanding Performance-based Options

(options in thousands; exercise price in dollars)

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

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

Performance Stock Units

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

Outstanding Performance Stock Units

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

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

Pro forma Compensation Expense

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

(millions of dollars, except per share amounts)

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

1 Total stock-based compensation expense if the fair value based method to expense all outstanding stock options had been applied since January 1, 2002.
2 Stock-based compensation recognized as an expense in the statement of earnings for options and performance stock units granted in 2003 through 2005 as a result of the adoption of the fair-value based method on January 1, 2003.

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

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

Contributed Surplus

(millions of dollars)

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

18. FINANCIAL INSTRUMENTS

Derivative Financial Instruments Used for Risk Management

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

Foreign Exchange

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

Interest Costs

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

Energy Commodity Costs

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

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

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

Natural Gas Supply Management

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

Credit Risk

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

Fair Values

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

(millions of dollars unless otherwise noted)

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

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

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

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

18. FINANCIAL INSTRUMENTS (continued)

Interest Rate Management

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

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

1 *After giving effect to the derivative financial instruments.*

Fair Values of Other Financial Instruments

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

Total Debt

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

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

Trade Credit Risk

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

19. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars)

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

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

Components of Future Income Taxes

(millions of dollars)

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

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

19. INCOME TAXES (continued)

Geographic Components of Pretax Earnings and Income Taxes

(millions of dollars)

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

20. POST-EMPLOYMENT BENEFITS

Pension Plans

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

Defined Benefit Plans

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

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

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

Defined Contribution Plans

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

Post-employment Benefits Other than Pensions

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

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

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

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

20. POST-EMPLOYMENT BENEFITS (continued)

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

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

Net Pension Plan and OPEB Costs Recognized

(millions of dollars)

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

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

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

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

Medical Cost Trend Rates

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

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

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

Major Categories of Plan Assets

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

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

Expected Rate of Return on Plan Assets

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

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

Plan Contributions by the Company

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

Benefits Expected to be Paid by the Company

(millions of dollars)

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

21. OTHER INVESTMENT INCOME

(millions of dollars)

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

22. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of dollars)

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

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

23. RELATED PARTY TRANSACTIONS

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

(millions of dollars)

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

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

(millions of dollars)

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

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

(millions of dollars)

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

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

(millions of dollars)

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

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

(millions of dollars)

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

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

(millions of dollars)

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

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

(millions of dollars)

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

23. RELATED PARTY TRANSACTIONS (continued)

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

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is determined and charged. The Company may also purchase consulting and other services from affiliates. Prices are determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

24. COMMITMENTS AND CONTINGENCIES

Enbridge Gas Distribution Inc.

Class Action Lawsuit – late payment penalties

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

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

Bloor Street Incident

EGD has been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. The maximum possible fine upon conviction on all charges would be $5.0 million in aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion has also been called, but the proceedings are stayed pending resolution of the TSSA and OHSA matters. The courts have not yet ruled upon any of the charges laid under the TSSA or the OHSA, and thus it is not possible at this time to predict or comment upon the potential outcome. The trial in respect of these charges commenced January 3, 2006. EGD does not expect the outcome of these civil actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

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

CAPLA Claim

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

Enbridge Energy Company, Inc.

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

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

Olympic Pipe Line Company

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

25. GUARANTEES

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

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

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

25. GUARANTEES (continued)

Sale Agreements for Assets or Businesses

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

Provision of Services and Other Agreements

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

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

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

26. UNITED STATES ACCOUNTING PRINCIPLES

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

Earnings and Comprehensive Income

(millions of dollars, except per share amounts)

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

Financial Position

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

1 *Stock-based Compensation*

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

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

2 *Future Income Taxes*

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

3 *Accounting for Joint Ventures*

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

4 *Financial Instruments*

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

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

26. UNITED STATES ACCOUNTING PRINCIPLES (continued)

5 Accumulated Other Comprehensive Loss

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

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

6 Consolidation of Variable Interest Entities

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

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

Statement of Financial Position

(millions of dollars)	December 31, 2004
Cash	14.8
Accounts receivable and other	22.7
Property, plant and equipment, net	1,267.8
Deferred amounts and other assets	42.0
Intangible assets	108.3
Goodwill	308.1
	1,763.7
Less: Liabilities	
Accounts payable and other	22.7
Current portion of non-recourse long-term debt	41.5
Non recourse long-term debt	1,045.3
Other long-term liabilities	6.7
Future income taxes	92.1
Non-controlling interests	175.0
	1,383.3
	380.4
Elimination of investment in EIF	(380.4)
Net financial position impact	nil

Statement of Earnings

(millions of dollars)	Year ended December 31, 2004	Six months ended December 31, 2003
Transportation revenue	239.8	126.0
Operating and administrative	(61.8)	(31.6)
Depreciation and amortization	(70.1)	(34.9)
Other investment income	(5.2)	(4.5)
Interest expense	(60.3)	(31.3)
Income taxes	1.2	(0.3)
	43.6	23.4
Elimination of EIF investment income	(43.6)	(23.4)
Net earnings impact	nil	nil

Statement of Cash Flows *(millions of dollars)*	Year ended December 31, 2004	Six months ended December 31, 2003
Operating activities	54.5	24.2
Investing activities	(14.7)	(359.4)
Financing activities	(52.6)	362.8
Net cash flow impact	(12.8)	27.6

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,	**2005**	2004	2003
Earnings under U.S. GAAP			
As reported	**539.4**	645.3	634.9
Stock-based compensation expense	**(27.5)**	(8.2)	(7.9)
Included as an expense in the statement of earnings	**24.8**	4.2	1.9
Pro forma	**536.7**	641.3	628.9
Earnings per common share			
As reported	**1.60**	1.93	1.92
Pro forma	**1.59**	1.92	1.90
Diluted earnings per common share			
As reported	**1.58**	1.92	1.90
Pro forma	**1.57**	1.91	1.88

New Accounting Standards

In June 2005, the U.S. Emerging Issues Task Force (EITF) reached a consensus on EITF issue 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (EITF 04-5), addressing when a general partner, or general partners as a group, control and should therefore, consolidate a limited partnership. Under EITF 04-5, a sole general partner is presumed to control a limited partnership when certain conditions are met. As a result, for the first reporting period beginning after December 15, 2005, it is expected that the Company will be required to include the accounts of EEP for U.S. GAAP purposes.

Supplementary Information

Quarterly Share Trading Information[1]

The Toronto Stock Exchange

2005 *(dollars)*	First	Second	Third	Fourth
High	**32.40**	**36.19**	**38.50**	**38.82**
Low	**28.59**	**30.70**	**33.31**	**33.05**
Close	**31.10**	**34.95**	**37.26**	**36.34**
Volume (millions)	**82.1**	**57.5**	**35.7**	**36.0**

2004 *(dollars)*	First	Second	Third	Fourth
High	27.50	27.20	26.68	30.08
Low	25.18	23.80	23.63	25.53
Close	26.65	24.36	26.38	29.85
Volume (millions)	45.6	47.4	31.4	31.0

The New York Stock Exchange

2005 *(U.S. dollars)*	First	Second	Third	Fourth
High	**26.38**	**29.02**	**32.70**	**33.11**
Low	**20.68**	**24.80**	**27.80**	**28.15**
Close	**25.74**	**28.50**	**31.92**	**31.27**
Volume (millions)	**8.2**	**8.4**	**13.7**	**7.9**

2004 *(U.S. dollars)*	First	Second	Third	Fourth
High	21.16	20.63	20.93	25.00
Low	18.86	17.59	18.19	20.35
Close	20.35	18.30	20.82	24.89
Volume (millions)	1.6	1.8	1.6	3.8

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

Five-Year Consolidated Highlights

Financial and Operating Information[1]

(millions of Canadian dollars)

Earnings by Segment	**2005**	2004	2003	2002	2001
Liquids Pipelines	**229.1**	219.9	213.5	189.6	164.4
Gas Pipelines	**59.8**	53.8	70.1	47.8	41.5
Sponsored Investments	**64.8**	66.2	234.3	(51.1)	37.2
Gas Distribution and Services	**178.8**	313.1	153.6	124.3	189.6
International	**87.4**	73.6	72.3	68.0	35.6
Corporate	**(63.9)**	(81.3)	(76.6)	(48.6)	(55.1)
Continuing operations	**556.0**	645.3	667.2	330.0	413.2
Discontinued operations	**–**	–	–	242.3	45.3
Earnings applicable to common shareholders	**556.0**	645.3	667.2	572.3	458.5
Adjusted operating earnings applicable to common shareholders[2]	**537.2**	491.1	495.5	428.4	387.8
Cash Flow Data					
Cash provided from operating activities	**903.5**	886.7	368.5	877.4	397.0
Expenditures on property, plant and equipment	**680.6**	496.4	391.3	729.9	683.3
Acquisitions and long-term investments	**178.5**	850.5	128.8	1,572.0	640.9
Dividends paid on common shares	**361.1**	315.8	283.9	251.1	227.5
Operating Data					
Liquids Pipelines[3]					
Deliveries *(thousands of barrels per day)*	**2,008**	2,138	2,189	2,088	2,109
Barrel miles *(billions)*	**695**	757	710	705	695
Average haul *(miles)*	**949**	970	889	925	903
Gas Distribution and Services[4]					
Distribution volume *(billion cubic feet)*	**438**	575	458	410	427
Number of active customers *(thousands)*	**1,805**	1,756	1,679	1,623	1,571
Degree day deficiency[5]					
Actual	**3,750**	5,052	4,029	3,362	3,766
Forecast based on normal weather	**3,747**	4,849	3,565	3,700	3,816

1 *Financial and operating highlights of Gas Distribution and Services for 2004 reflect earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution (EGD), Noverco and other gas distribution entities. This resulted from the elimination of the quarter lag basis of consolidation in 2004. For the years ended December 31, 2001 through 2003, earnings are for the 12 months ended September 30 for these entities. For the year ended December 31, 2005, earnings are for the 12 months ended December 31 for these entities.*

2 *Adjusted operating earnings applicable to common shareholders represent earnings applicable to common shareholders adjusted for non-operating factors including primarily gains and losses, weather, regulatory disallowances and impacts of tax rate changes. Earnings for 2004 and 2003 have been adjusted to eliminate the quarter lag basis of consolidation described above. This is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure. Therefore, this measure may not be comparable with a similar measure presented by other issuers. Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends.*

3 *Liquids Pipelines operating highlights include the statistics of the 10.9% owned Lakehead System and other wholly-owned liquid pipeline operations.*

4 *Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

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.*

Five-Year Consolidated Highlights

Shareholder and Investor Information[1]

(per share amounts in dollars)	**2005**	2004	2003	2002	2001
Average common shares outstanding weighted monthly during the year *(thousands)*	**337,447**	334,480	330,942	320,620	314,594
Common Share Trading (TSX)					
High	**38.82**	30.08	27.07	24.63	22.78
Low	**28.59**	23.63	20.48	20.56	16.95
Close	**36.34**	29.85	26.85	21.31	21.70
Volume *(millions)*	**211.3**	155.4	150.2	144.6	135.2
Per Common Share Data					
Earnings applicable to common shareholders					
Continuing operations	**1.65**	1.93	2.02	1.03	1.32
Discontinued operations	**–**	–	–	0.76	0.14
	1.65	1.93	2.02	1.79	1.46
Adjusted operating earnings applicable to common shareholders[2]	**1.59**	1.47	1.50	1.34	1.23
Dividends paid on common shares	**1.04**	0.92	0.83	0.76	0.70
Financial Ratios					
Return on average shareholders' equity[3]	**13.2%**	17.0%	19.0%	18.3%	17.4%
Return on average capital employed[4]	**6.9%**	8.3%	8.3%	7.3%	7.1%
Debt to debt plus shareholders' equity[5]	**68.9%**	67.1%	68.7%	69.4%	75.9%
Debt to total capital employed[6]	**71.0%**	67.2%	66.1%	61.9%	77.3%
Earnings coverage of interest[7]	**2.4x**	2.8x	2.7x	2.5x	2.1x
Dividend payout ratio[8]	**65.2%**	62.3%	55.3%	56.9%	56.8%

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

2 Adjusted operating earnings applicable to common shareholders represent earnings applicable to common shareholders adjusted for non-operating factors including primarily gains and losses, weather, regulatory disallowances and impacts of tax rate changes. Earnings for 2004 and 2003 have been adjusted to eliminate the quarter lag basis of consolidation described above. This is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure. Therefore, this measure may not be comparable with a similar measure presented by other issuers. Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends.

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

4 Sum of after-tax earnings (including earnings from discontinued operations) and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).

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

6 Total debt (including short-term borrowings) divided by capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).

7 Sum of before-tax earnings and interest expense divided by interest expense (including capitalized interest).

8 Dividends per common share divided by adjusted operating earnings per share applicable to common shareholders.

Enbridge Awards and Recognition in 2005

Corporate Social Responsibility

- *Dow Jones Sustainability Index 2005/06:* Enbridge was added to the Dow Jones Sustainability World Index for 2005/06, effective September 19, 2005. The prestigious global ranking evaluates companies on economic, environmental and social criteria.

- *Global 100 Most Sustainable Corporations in the World:* A new global ranking that reviewed 2,000 companies for their ability to manage strategic opportunities in new environmental and social markets named Enbridge as one of the top 100 companies in the world. Enbridge was one of six Canadian companies included in the listing that was announced at the World Economic Forum at Davos, Switzerland, in January 2005, and one of five in the listing that was announced in January 2006.

- *Canada's Top 100 Employers:* Enbridge was named to the 2006 listing of Canada's Top 100 Employers and also named as one of Alberta's Top 20 Employers.

- *Thanks a Million Award:* For the sixth year in a row, Enbridge was recognized by the United Way and Centraide as a recipient of their Thanks a Million Award for raising more than $1 million for United Way and Centraide campaigns in Canada in 2004.

- *Corporate Knights Best 50 Corporate Citizens Ranking 2005:* Enbridge was ranked 47th in the listing of the best 50 Canadian corporate citizens.

- *Alberta Venture magazine's Most Respected Corporations in Alberta 2005:* Enbridge was selected the Most Respected Corporation for Community Involvement.

- *Best Places to Work in Houston:* The Enbridge/Enbridge Energy Partners Houston office was named one of the *Best Places to Work in Houston* by the Houston Business Journal. Enbridge was in the top 10 in its category.

Corporate Governance

- *The Globe and Mail Report on Business Annual Corporate Governance Evaluation 2005:* Enbridge Inc. tied for 12th scoring 93 out of a possible 102 points (best score was 97).

- *Canadian Business Magazine 2005:* Enbridge tied for 15th best Board of Directors scoring 92 (best score was 99).

- *Canadian Coalition for Good Governance 2005:* Enbridge was one of three honourable mentions for the first Canadian Coalition for Good Governance Golden Gavel Award for effective disclosure of director information.

- *Clarity Communications of Canada Inc. ranking of the Top 10 S&P/TSX60 Investor Relations websites:* announced December 2, 2005, Enbridge Inc. ranked #5.

Investor Information

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, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States

Mellon Investor Services
P.O. Box 590
Ridgefield Park, NJ, 07660-0590 U.S.A.
Toll free: (800) 526-0801

Preferred Securities

The Preferred Securities, Series D, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.D". 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, with offices in Montreal, Toronto, Winnipeg, Edmonton and Vancouver.

Auditors

PricewaterhouseCoopers LLP

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.

Le présent document est disponible en français.

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

New York Stock Exchange Disclosure Differences

As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies under NYSE listing standards. This disclosure can be obtained from the *U.S. Compliance* subsection of the *Corporate Governance* section of the Enbridge website at **www.enbridge.com**.

Annual Meeting

The Annual 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 3, 2006.

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.

Registered Office

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920
Internet: **www.enbridge.com**

2006 Dividend Information for Common Shares and Preferred Shares, Series A*	1st Q	2nd Q	3rd Q	4th Q
Record date	Feb. 15	May 15	Aug. 15	Nov. 15
Payment date	March 1	June 1	Sept. 1	Dec. 1
Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date	Feb. 8	May 8	Aug. 8	Nov. 8
Common Share Purchase Plan cut-off date for DRIP	Feb. 22	May 25	Aug. 25	Nov. 24

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

2006 Interest Payment Information for Preferred Securities, Series 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

Creative Development by Rivard Design Inc.,
Full-page black and white photography by Brodylo/Morrow Photography.
Printed by Grafikom Calgary.

Printed on paper manufactured entirely with wind energy.

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**".

Dividends have increased an average of

8.5%

per year for the past decade

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Fax: (403) 231-3920
Toll free line: (800) 481-2804
www.enbridge.com