ENBRIDGE ENERGY PARTNERS LP
Form 10-K
February 23, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 2005

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**39-1715850** (I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, Texas 77002

(Address of principal executive offices and zip code)

(713) 821-2000

(Registrant s telephone number, including area code)

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

Title of each class	**Name of each exchange on which registered**
Class A Common Units	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer x Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

The aggregate market value of the Registrant s Class A Common Units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2005, was $2,503,940,919.

As of February 17, 2006, the Registrant has 49,938,834 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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This Annual Report on Form 10-K contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as anticipate, believe, continue, estimate, expect, forecast, intend, may, plan, position, projection, strategy, could, should, or will or the negative of those terms or other variations of them or comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see Item 1A. Risk Factors included elsewhere in this Form 10-K.

Glossary

The following abbreviations, acronyms, or terms used in this Form 10-K are defined below:

AEUB	Alberta Energy and Utilities Board
Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle, which were acquired on October 17, 2002
AOSP	Athabasca Oil Sands Project, located in northern Alberta, Canada
Bbl	Barrel of liquids (approximately 42 U.S. gallons)
BlackRock	BlackRock Ventures Inc., an unrelated producer of heavy oil in Western Canada
Bpd	Barrels per day
CAA	Clean Air Act
Canadian Natural	Canadian Natural Resources Limited, an unrelated energy company
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of the Lakehead system's customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CAD	Amount denominated in Canadian dollars
CWA	Clean Water Act
DOT	Department of Transportation
East Texas system	Natural gas gathering, treating and processing assets in East Texas acquired on November 30, 2001. Also includes a system formerly known as the Northeast Texas system
Enbridge	Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner
Enbridge Management	Enbridge Energy Management, L.L.C.
Enbridge system	Canadian portion of the System
Enbridge Pipelines	Enbridge Pipelines Inc.
EnCana	EnCana Corporation, an unrelated producer of natural gas
EP Act	Energy Policy Act of 1992
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area
ICA	Interstate Commerce Act
KPC	Kansas Pipeline system, acquired on October 17, 2002
Lakehead Partnership	Enbridge Energy, Limited Partnership, a subsidiary of the Partnership

Lakehead system	U.S. portion of the System
LIBOR	London Interbank Offered Rate British Bankers Association's average settlement rate for deposits in U.S. dollars
M3	Cubic meters of liquid = 6.289811661 Bbl
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
Midcoast system	Natural gas gathering, treating, processing, transmission and marketing assets acquired October 17, 2002
Mid-Continent system	Crude oil pipelines and storage facilities located in the mid-continent of the U.S. and acquired on March 1, 2004
NEB	National Energy Board, a Canadian federal agency that regulates Canada s energy industry
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
North Dakota system	Liquids petroleum pipeline system in the Upper Midwest United States acquired on May 18, 2001
Northeast Texas system	Natural gas gathering and processing assets acquired on October 17, 2002 and integrated with the East Texas system
North Texas system	Natural gas gathering and processing assets acquired on December 31, 2003
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts, and other energy futures are traded
NYSE	New York Stock Exchange
OCSLA	Outer Continental Shelf Lands Act
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
PADD	Petroleum Administration for Defense Districts
PADD II	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin
PADD III	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
PADD IV	Consists of Idaho, Montana, Wyoming and Colorado
PADD V	Consists of Washington, Oregon, California, Arizona, Alaska, Hawaii and Nevada
Palo Duro system	Natural gas transmission and gathering pipeline assets located in Texas between the Anadarko system and the North Texas system acquired on March 1, 2004 and integrated with the Anadarko system during 2005

Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of the Partnership
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration (formerly OPS)
PPIFG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
PSI Act	Pipeline Safety Improvement Act
RCRA	Resource Conservation & Recovery Act
SAGD	Steam assisted gravity drainage
SEC	Securities and Exchange Commission
SEP II	System Expansion Program II, an expansion program on the Lakehead system
Settlement Agreement	A FERC approved settlement agreement, signed October 1996
SFAS	Statement of Financial Accounting Standards
SFAS No. 133	Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities*
SFPP	Sante Fe Pacific Pipelines, L.P., an unrelated company
Suncor	Suncor Energy Inc., an unrelated company
Syncrude	Syncrude Canada Ltd., an unrelated company
Synthetic crude oil	Product that results from upgrading or blending bitumen into a crude oil stream which can be readily refined by most conventional refineries
System	The combined liquid petroleum pipeline operations of the Lakehead system and the Enbridge system
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace	Terrace Expansion Program, an expansion program on the Lakehead system
WCSB	Western Canadian Sedimentary Basin

PART I

Item 1. Business

OVERVIEW

In this report, unless the context requires otherwise, references to we, us, our, or the Partnership are intended to mean Enbridge Energy Partners L.P. and its consolidated subsidiaries. We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the NYSE under the symbol EEP.

We were formed in 1991 by our general partner to own and operate the Lakehead system, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada. A subsidiary of Enbridge owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, provides energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our general partner.

We are a geographically and operationally diversified partnership consisting of interests and assets relating to the midstream energy sector. As of December 31, 2005, our portfolio of assets include the following:

- Approximately 4,900 miles of crude oil gathering and transportation lines and 23.4 million Bbl of crude oil storage and terminaling capacity.

- Natural gas gathering and transportation lines totaling approximately 11,000 miles.

- Eight active natural gas treating and 15 active natural gas processing facilities with aggregate capacity of approximately 1,500 MMcf/d.

- Trucks, trailers and railcars for transporting NGLs, crude oil and carbon dioxide.

- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our general partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. The General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of a special class of our limited partner interests, which we refer to as i-units.

Our ownership at December 31, 2005 is comprised of the following:

	2005	
Class A common units owned by the public	74.7	%
Class B common units owned by our general partner	5.8	%
i-units owned by Enbridge Management	17.5	%
General Partner interest	2.0	%
	100.0	%

BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unitholders, while maintaining a relatively low investment risk profile. Our business strategies focus on creating value for our

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customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Expand existing core asset platforms

- We intend to develop and acquire energy transportation assets and related facilities that are complementary to our existing systems. Our core businesses provide plentiful opportunities to achieve our primary business objectives.

2. Develop new asset platforms

- We plan to develop new gathering, processing, transportation and storage assets to meet customer needs, by expanding capacity into new markets with favorable supply and demand fundamentals.

3. Focus on operational excellence

- We will continue to operate our existing infrastructure to maximize cost efficiencies, provide flexibility for our customers and ensure the capacity is reliable and available when required. We will focus on safety, environmental integrity, innovation and effective stakeholder relations.

In our current environment, our primary focus is on expanding and developing our existing assets. We are placing relatively less emphasis on acquisitions than in prior years due to:

- Acquisition prices for the stable energy assets we seek have become inflated; and

- The expansion and diversification of our asset base over the past few years has created opportunities for internal growth projects that are expected to enhance the value of services we provide to our customers and returns to our investors.

While purchase prices remain high, our acquisitions will likely be limited to situations where we have natural advantages, through reduced costs or increased utilization of our services.

Our planned internal growth for both our liquids and natural gas businesses will require a significant investment of expansion capital over the next few years. While these major projects are under construction, our ability to increase distributions, while also funding these projects, is likely to be limited. Our outlook is premised on a number of major assumptions regarding the scope and timing of the projects, financing alternatives available to us and excludes the potential of significant acquisitions during the period. We expect our larger growth projects will be accretive to distributable cash flow when placed into service. These projects are discussed below in the respective business section.

Liquids

Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2005 from the U.S. Department of Energy s Energy Information Administration, Canada supplied approximately 1.6 million Bpd of crude oil to the U.S., the largest source of U.S. imports. Of the Canadian crude oil moving into the U.S., about 63% was transported on the System, which is the primary pipeline from western Canada to the U.S. We are well positioned to develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta oil sands. With an estimated $55 billion of active or planned projects in the Alberta oil sands, new production is expected to grow steadily during the next 5 years, with an additional 700,000 Bpd available by 2010 according to the AEUB.

Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply. Our $1.1 billion (in 2005 dollars) project will provide an additional 400,000 Bpd of heavy oil capacity to the Chicago market and beyond by early 2009, with nearly half of this capacity

available in early 2008. The design will also permit a further 400,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior, when required by shippers. The Southern Access project involves new pipeline construction on our Lakehead system along with expansion on the Canadian portion of the pipeline by Enbridge.

Along with Enbridge, we are actively working with our customers to develop options that will allow Canadian crude oil to access new markets. The market strategy we are undertaking is to provide timely, economical, integrated transportation solutions to connect growing supplies of production from the Alberta oil sands to key refinery markets in the United States. The strategy involves further penetration into PADD II as well as entry into the vast refining center of the U.S. Gulf Coast. On April 28, 2005, the NEB approved two applications from Enbridge Pipelines to recover the costs for the extension of service to other markets via Enbridge s Spearhead pipeline and ExxonMobil s Mobil Pipe Line through its Canadian tolls over the next 5 years. Through these initiatives, western Canadian crude oil will be delivered into Cushing, Oklahoma and Beaumont, Texas respectively in the first quarter 2006. We expect to benefit from these initiatives, as western Canadian crude oil will be carried on our Lakehead system as far as Chicago and then transferred to these other pipelines to access the new markets.

Natural Gas

Our natural gas assets are primarily located in the U.S. Gulf Coast region, one of the most active natural gas producing areas in the United States. Three of our larger systems in Texas are located in basins that have experienced recent growth in natural gas land leases, drilling and production. These core basins are known as: the East Texas basin, the Barnett Shale area and the Anadarko basin. Our focus has been on acquiring assets with strong growth prospects located in these areas and then to continue to develop those prospects.

One of our key objectives is to become the premier midstream energy company in the U.S. Gulf Coast region. To achieve this end, the operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategy is to provide safe reliable service at reasonable costs to our customers, to enhance our reputation with our customers and to improve our competitiveness for capturing new customers. From a commercial perspective, our focus is to improve the value of service to our customers by providing them with a better value for their commodity. We intend to achieve this objective by increasing customer access to the natural gas markets. We have made significant progress on this objective by physically connecting a number of our systems. The objective is to be able to move significant quantities of natural gas from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana. From the market hubs, natural gas can be transported to consumers in the Midwest and Northeast United States. Our trucking operations are used to enhance the value of the NGLs produced at our processing plants by ensuring ready access to strategic markets. Our marketing business also helps maximize the value received for the natural gas we transport and purchase, by identifying customers with consistent demand for natural gas.

The growth prospects in our core areas have been improving due to the sustained high commodity prices and improvements in technology to produce natural gas from tight sand and shale formations. As a result, many expansions and extensions have been made on three of our main gathering and processing systems in Texas, including well-connects, processing plant re-activations, new plant construction, added compression and new pipelines. During January 2005, we purchased additional natural gas gathering and processing assets in north Texas, which we have integrated with our existing North Texas assets.

We continue to work closely with our customers to provide natural gas transportation solutions to avoid shut-in natural gas production from insufficient transportation capacity. During 2005, we completed construction of a new 500 MMcf/d intrastate transportation pipeline to carry increased volumes of natural gas to the pipeline hub at Carthage, Texas. Carthage access is important because it offers a number of connections to interstate pipelines, which tend to support more favorable natural gas prices for our customers. In January 2006, we announced another $530 million expansion and extension of our East Texas system. This project is required to handle the strong growth occurring in East Texas natural gas production, particularly from the Bossier Sands and other regional producing formations. We coordinated extensively with our customers to develop and enhance access for growing Texas natural gas production to major markets in southeast Texas. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

We are also working with Enbridge on its proposed interstate extension from our Texas natural gas midstream business. Enbridge announced an Open Season on a proposed 330 mile, 1 billion cubic feet per day pipeline from Texas through Louisiana, to interconnects with other interstate systems in western Mississippi. This project, if supported by shippers, could draw additional volumes through our East Texas system and its proposed expansion announced in January 2006.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- Liquids;
- Natural Gas; and
- Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 16 of our consolidated financial statements.

Liquids Segment

Lakehead system

The Lakehead system consists primarily of a crude oil and liquid petroleum common carrier pipeline and storage assets in the Great Lakes and Midwest regions of the United States. This system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. The System, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The System serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. Through its interconnection with the Enbridge system, the Lakehead system is well positioned to capitalize on expected increases in crude oil supplies from previously announced heavy crude oil and oil sands projects in the Province of Alberta, Canada.

Our Lakehead system is a FERC-regulated interstate common carrier pipeline system. The Lakehead system spans a distance of approximately 1,900 miles, and consists of approximately 3,500 miles of pipe with diameters ranging from 12 inches to 48 inches, 59 pump station locations with a total of approximately 768,000 installed horsepower and 62 crude oil storage tanks with an aggregate working capacity of approximately 10.8 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 59 crude oil commodities including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2005, 42 shippers tendered crude oil and liquid petroleum for delivery through the

Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is well positioned as the primary transporter of western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta oil sands. Similar to U.S. domestic conventional crude oil production, western Canada s conventional crude oil production is declining. Over the last several years, development of the Alberta oil sands resource has more than offset declining conventional production. In 2005, due to a major disruption at Suncor s oil sands production facilties, growth in Alberta oil sands production did not offset the decline in production from conventional resources. The NEB estimates the total WCSB 2005 production will average 2.1 million Bpd. Despite the decline experienced in 2005, WCSB crude oil production is comparable with production from key OPEC members Kuwait and Venezuela.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.8 billion barrels at the end of 2004. During 2004, the latest period for which data is available, approximately 95% of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta oil sands as of the end of 2004, stand at approximately 174 billion barrels. Combined conventional and oil sands established reserves of approximately 178 billion barrels compares with Saudi Arabia s proved reserves of approximately 260 billion barrels.

According to the CAPP, an estimated $30 billion has been spent on oil sands development from 1996 through 2004. The Alberta government estimates that an additional $55 billion may be spent by 2015, including approximately $15 billion in maintenance capital on existing projects. This estimate includes all announced and planned projects in the Alberta oil sands. While it is unlikely that all projects will proceed as planned, the magnitude of the potential is significant. Separately, the AEUB estimates future production from the Alberta oil sands will increase by more than 1.5 million barrels per day by 2014 based on a subset of currently approved applications and announced expansions.

The near-term growth in crude oil supply comes from the completion of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new SAGD facilities currently under construction in Alberta. Over the next year, synthetic crude oil production capacity is expected to increase by approximately 110,000 Bpd at the existing plants over 2005 levels. Syncrude, one of the original oil sands producers in northern Alberta, is expected to complete their Stage 3 expansion in mid-2006, increasing production capacity to 350,000 Bpd from current capacity of 240,000 Bpd. Suncor, the other original oil sands producer in Alberta, returned to full production after a fire and completed an expansion of their existing plant both at their upgrader and their SAGD production facility during the fourth quarter of 2005. The expansion increased their production capacity by 35,000 Bpd to 260,000 Bpd**.**

The AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Western Oil Sands L.P. (20%), is another oil sands project that reached full production capacity in 2004. Over the next three years, AOSP is planning on a number of programs to increase production by 2010 from 155,000 Bpd to 300,000 Bpd**.** Regulatory applications for this project were filed in April 2005. De-bottlenecking initiatives related to bitumen production increased output in the second and third quarters of 2005 to average approximately 165,000 Bpd.

Over the next two years, unblended bitumen production is expected to start or increase from nearly 20 individual projects. Notable projects include the expansions at Canadian Natural s Wolf Lake/Primrose area, EnCana s Foster Creek, Suncor s Firebag and BlackRock s Seal project. Based on the AEUB forecast, unblended bitumen production is expected to increase by roughly 120,000 Bpd by the end of 2007, more than offsetting the decline in conventional crude production.

Although the crude oil and liquid petroleum delivered through the Lakehead system primarily originates in oilfields in western Canada, the Lakehead system also receives approximately 6% of its receipts from domestic sources including:

- United States production at Clearbrook, Minnesota through a connection with the North Dakota system;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Based on forecasted growth in western Canadian crude oil production and completion of repairs by Suncor to its upgrader that was damaged in early 2005 by a fire, we expect the Lakehead system deliveries to average 1.58 million Bpd in 2006 compared with 1.34 million Bpd in 2005. During December 2005, the Lakehead system achieved deliveries averaging 1.49 million Bpd. The estimated deliveries for 2006 are part of a forecast representing forward-looking information and are subject to risks, uncertainties and factors beyond our control.

Our ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon numerous factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers expectations of crude oil and natural gas prices, future operating costs, and availability of markets for produced crude. Higher crude oil production from the WCSB should result in higher deliveries on the Lakehead system. Deliveries on the Lakehead system are also affected by periodic maintenance, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

We expect the demand for WCSB crude oil production will continue to increase in PADD II. PADD II refinery configurations and crude oil requirements continue to be an attractive market for western Canadian supply. According to the U.S. Department of Energy s Energy Information Administration, 2005 demand for crude oil in PADD II remained relatively unchanged from 2004 with an average of 3.3 million Bpd. At the same time, production of crude oil within PADD II increased marginally by 3,000 Bpd to 438,000 Bpd. With the proximity of the WCSB to PADD II, the availability of capacity on the Lakehead system and limited alternative markets for WCSB production, we expect deliveries on the Lakehead system to increase along with increases in WCSB supply. Based on our industry survey, we expect refineries in the PADD II market to compete aggressively with new markets for access to the growing supply from the WCSB.

After receiving strong shipper support during the summer Open Season, the Partnership and Enbridge announced in December 2005, the approval of the 400,000 Bpd Southern Access expansion project. The expansion is endorsed by CAPP, which allows us and Enbridge to file negotiated settlements containing tariff rate surcharge terms with Canadian and U.S. regulatory authorities. Fieldwork on the expansion has commenced to ensure completion in early 2009, with capacity increases to start in 2007.

The U.S. portion of the expansion will be undertaken on our Lakehead system with the first stage to add 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The first stage includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The expansion project s second stage will add upstream pumping capacity and complete construction of a new pipeline from Delavan to Flanagan, Illinois, with completion in early 2009. The Southern Access expansion project will create a new 454-mile 36-inch diameter pipeline that will add 400,000 Bpd of incremental heavy crude oil capacity to our Lakehead system. The design will also permit a further 400,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior, when required by shippers. For the U.S. portion of the expansion, the total costs are currently estimated at approximately $1.1 billion (in 2005 dollars). Enbridge is also working with CAPP and shippers to extend the pipeline further south to Wood River and Patoka, Illinois, to provide capacity for further Canadian crude oil movements to the markets being served from these hubs, which is referred to as the Southern Access extension. The Southern Access extension would be owned by Enbridge but integrated with the Lakehead system operationally and for tariff tolling purposes.

Enbridge recently announced plans to develop the 400,000 Bpd Alberta Clipper Pipeline for a cost of $1.6 billion (2005 dollars), as an express heavy crude oil line from Hardisty, Alberta to Superior, where it would connect with our Lakehead system. The Alberta Clipper Pipeline is not expected to be integrated with the System for tolling purposes and would be separate from our Lakehead system. However, we will have an opportunity to develop the United States section of this line at an expected cost of approximately $570 million (in 2005 dollars). This expansion of capacity upstream of Superior would be timed to meet the need for further capacity over and above our Southern Access expansion. The current design of our Southern Access expansion permits further development downstream of Superior, and this would be undertaken in conjunction with the construction of the Alberta Clipper Pipeline. The Alberta Clipper Pipeline together with further expansion of our portion of the Southern Access project, provides a highly economical source of additional capacity from Alberta to the U.S. Midwest, and offers shippers the greatest range of storage and delivery locations.

The Spearhead pipeline is a 650-mile crude oil pipeline originally flowing from Cushing to Chicago which Enbridge purchased in 2003. On March 2, 2005, Enbridge received FERC approval to proceed with plans to reverse the direction of flow on the pipeline from a northerly flow to a southerly flow. Shippers have contracted for 10-year shipping commitments of an initial 60,000 Bpd, increasing to 75,000 Bpd by 2009. Enbridge expects to have the line in service during the first quarter of 2006, with initial capacity of 125,000 Bpd. The line could subsequently be expanded to accommodate up to 160,000 Bpd. The reversed line will originate from the Griffith, Indiana terminal on our Lakehead system and the connection to this new market should support increased throughput on the Lakehead system.

During 2004, ExxonMobil Pipeline Company approached CAPP and prospective shippers with a proposal to reverse the direction of flow on their Beaumont, Texas to Corsicana, Texas and their Corsicana, Texas to Patoka crude oil pipelines. The combined reversed pipeline will be linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka. Mustang Pipe Line Partners system is 30% owned by an affiliate of Enbridge. The reversed pipeline is expected to transport between 50,000 and 70,000 Bpd of WCSB crude oil to the refinery market located in Beaumont on the U.S. Gulf Coast. The connection of our Lakehead system with this new market should also support increased throughput on our Lakehead system in early 2006; however, the reversed system will also be capable of transporting WCSB crude oil moved via other competing pipelines into the Patoka market.

The previously announced closure of an Oakville, Ontario refinery was completed in April 2005. A portion of the facility was closed in the fall of 2004, resulting in a modest decline in the volume of crude oil delivered by our Lakehead system to the province of Ontario. Future Lakehead system deliveries into Ontario are expected to remain relatively constant at this 2004 reduced level.

Competition. Our Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB. WCSB production in excess of western Canadian demand moves on existing pipelines into the Midwest area of the United States (PADD II), the Rocky Mountain states (PADD IV), and the Anacortes area of Washington State (PADD V). In each of these areas, WCSB crude oil competes with local and imported crude oil to feed refineries to produce refined products (mainly gasoline, diesel, and jet fuel). As local crude oil production declines and refineries demand more imported crude oil in each PADD, imports from the WCSB increase. For 2005, the latest data available shows that PADD II demanded 3.3 million Bpd while producing 438,000 Bpd, thus importing 2.9 million Bpd. For the first nine months of 2005, PADD II imported approximately 0.9 million Bpd of crude oil from Canada. The remaining 2 million Bpd was imported from PADD III and offshore sources through the U.S. Gulf Coast. Of the crude oil imported from Canada, 2005 actual volumes transported on our Lakehead system averaged 995,000 Bpd. Deliveries of Canadian crude oil by our Lakehead system to PADD II declined by approximately 35,000 Bpd in 2005, a 3% decrease from 2004 volumes. Total deliveries on our Lakehead system averaged 1.34 million Bpd in 2005, meeting approximately 81 percent of Minnesota refinery capacity; 57 percent of the greater Chicago area; and 78 percent of Ontario s refinery demand.

In 2005, the Enbridge system transported approximately 65% of western Canadian crude oil production to export markets, Ontario, and interconnecting pipelines. The System also transported all of the NGL mix produced in western Canada. The remaining production was transported by systems serving the British Columbia, PADD IV and PADD V markets. Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 69% of the total western Canadian crude oil exports in 2005 to the United States.

Given the expected increase in crude oil production from the Alberta oil sands over the next 10 years, alternative transportation proposals have been presented to producers by us together with Enbridge, Enbridge on its own, and other competing entities. These proposals range from expansions of existing pipelines in markets currently served by western Canadian crude oil, to new pipeline construction, which would take the growth in production to new markets. These proposals are in various stages of development, with some at the concept stage, to others that are proceeding with regulatory approval. Each of these proposals could compete with our Lakehead system. The following provides an overview of these proposals put forth by Enbridge and competing entities:

- The expansion of an existing pipeline which begins in Clearbrook, Minnesota and transports western Canadian crude oil to St. Paul, Minnesota. This expansion would have the potential to increase the existing transportation capacity of the pipeline to 350,000 Bpd. While throughput on our Lakehead system from the Canadian border to Clearbrook could benefit from this expansion, volumes moving on our Lakehead system downstream of Clearbrook could be negatively impacted.

- The expansion of an existing pipeline that runs from Alberta to British Columbia and Washington state. The first phase of this expansion to add 35,000 Bpd of capacity was approved by the NEB in 2005 and is expected to be in service in 2007. The next phase would further increase capacity by another 40,000 Bpd by the end of 2008.

- Construction of the new Gateway Pipeline by Enbridge, which could transport western Canadian crude oil from Alberta to the west coast of Canada, where it would then be shipped by tanker to China and other Asia-Pacific markets and California. In December 2005, Enbridge announced the successful conclusion of an Open Season for the Gateway Pipeline, which resulted in non-binding indications of interest that exceeded 400,000 Bpd. Enbridge is working with participating shippers to finalize binding precedent agreements.

- Construction of a new 590,000 Bpd crude oil pipeline from Hardisty, Alberta to Patoka, with an expected in-service date of late 2009. This proposal has support of long-term contracts for a total of 340,000 Bpd and is proceeding with regulatory filings in Canada and the United States.

- Construction of a new crude oil pipeline from northern Alberta directly to the U.S. Gulf Coast. This conceptual pipeline proposal is subject to shipper support and regulatory approval.

These competing alternatives for delivery of western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system beyond our Southern Access expansion, and for the development of Enbridge s Alberta Clipper Pipeline. They could also affect throughput on and utilization of the System. However, the System offers significant cost savings and flexibility advantages which are expected to continue to favor us and Enbridge as the preferred alternative for meeting shipper transportation requirements to the midwest United States.

The following table sets forth Lakehead system average deliveries per day and barrel miles for each of the five-year periods ended December 31, 2005.

	Deliveries				
	2005	**2004**	**2003**	**2002**	**2001**
	(thousands of Bpd)				
United States					
Light crude oil	241	275	258	266	292
Medium and heavy crude oil	791	785	741	665	663
NGL	4	4	4	6	5
Total United States	1,036	1,064	1,003	937	960
Ontario					
Light crude oil	146	174	174	171	174
Medium and heavy crude oil	59	81	68	83	77
NGL	98	103	109	111	104
Total Ontario	303	358	351	365	355
Total Deliveries	1,339	1,422	1,354	1,302	1,315
Barrel miles (billions per year)	363	367	345	341	333

Mid-Continent system

Our Mid-Continent system, which we acquired in the first quarter of 2004, is located within the PADD II district and is comprised of our Ozark pipeline, our West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. It includes over 480 miles of crude oil pipelines and 11.9 million barrels of crude oil storage capacity. Our Ozark pipeline transports crude oil from Cushing to Wood River where it delivers to ConocoPhillips Wood River refinery and interconnects with the WoodPat Pipeline, and the Wood River Pipeline, each owned by unrelated parties. Our West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Sinclair Oil Corporation s Tulsa refinery.

The storage terminals consist of 97 individual storage tanks ranging in size from 55,000 to 575,000 barrels. We expect to add nine new tanks during 2006 to our existing storage facilities in Cushing, which will increase our crude oil storage capacity by 3.2 million barrels. A portion of the storage facilities are used for operational purposes while we contract the remainder of the facilities with various oil market participants for storage capacity within the terminals. Contract fees include fixed monthly capacity fees as well as utilization fees, which are charged for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements and both long-term and spot storage arrangements with its shippers. During 2005, 26 shippers tendered crude oil for service by the Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average daily deliveries on the system were 236,000 Bpd for 2005. For 2006, we expect deliveries to be approximately 210,000 Bpd.

Supply and Demand. The Mid-Continent system is positioned to capture increasing near-term demand for imported crude oil from west Texas and the U.S. Gulf Coast as well as third-party storage demand. In 2005, PADD II imported 2.9 million barrels per day from outside of the PADD II region. The Lakehead system supplied roughly 1.0 million barrels per day of crude from Canada leaving 2.0 million barrels per day imported from PADD III and offshore sources. We expect the gap between local supply and demand for crude oil in PADD II to continue to widen, encouraging imports of crude oil from Canada, PADD III and foreign sources.

Competition. Our Ozark pipeline system currently serves an exclusive corridor between Cushing and Wood River. However, refineries connected to Wood River have crude supply options available from Canada via the Lakehead system, with a connection to the Mustang pipeline, an Enbridge affiliated system, and through a third party pipeline, which runs from western Canada and PADD IV. These same refineries also have access to U.S. Gulf Coast and foreign supply through the Capline pipeline system, which is owned by an unrelated group of five owners. In addition, refineries located east of Patoka with access to crude through the Ozark system, also have access to west Texas supply through the Texas Gulf pipeline owned by third parties. The Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago and El Dorado on third-party pipeline systems. With the reversal of the Spearhead pipeline, we expect western Canadian crude oil moving on Spearhead to increase the importance of Cushing as a terminal and pipeline origination area.

The storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders rely on storage capacity for a number of different reasons: batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Competitors to our storage facilities at Cushing include large integrated oil companies and other midstream energy partnerships.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate transportation system servicing the Williston Basin in North Dakota and Montana. Its crude oil gathering pipelines collect crude oil from points near producing wells in approximately 36 oil fields in North Dakota and Montana. Most deliveries from the North Dakota system are made at Clearbrook, Minnesota, to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with a capacity of approximately 80,000 barrels per day. The North Dakota system also has 17 pump stations and 11 terminaling facilities with an aggregate working storage capacity of approximately 700,000 barrels. We are beginning a $20 million expansion of this system to be complete in late 2006. This expansion is necessary to meet increased crude oil production from the Montana and North Dakota region.

Customers. Customers of the North Dakota system include producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to the largest integrated oil companies.

Supply and Demand. Like the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States, and the ability of crude oil producers to maintain their crude oil production and exploration activities.

Competition. Competitors of the North Dakota system include integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by the North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking operations. We purchase and/or gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission, or to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for pipeline transportation. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation, and sold as their individual components, including ethane, propane, butanes and natural gasoline. At December 31, 2005, we have approximately 8,500 miles of gathering pipelines, eight treating plants and 15 processing plants, excluding plants that are inactive. Our treating facilities have a combined capacity exceeding 700 MMcf/d while the combined capacity of our processing facilities is over 800 MMcf/d.

In January 2005, we acquired natural gas gathering and processing assets in north Texas. Facilities acquired include approximately 2,200 miles of gas gathering pipelines and four processing plants with aggregate processing capacity of 121 MMcf/d of natural gas. This system predominantly gathers gas produced from the Fort Worth Basin Conglomerate formation and is located in an area where future drilling is expected from producers extending the Barnett Shale play s western flank. Most of the gas is gathered at the wellhead and must be processed in order to meet downstream pipeline transportation specifications.

Our natural gas segment consists of the following major systems:

- East Texas system: Includes approximately 2,900 miles of natural gas gathering and transportation pipelines, six natural gas treating plants and three natural gas processing plants.

- Anadarko system: Consists of approximately 1,200 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle, one natural gas treating plant and four natural gas processing plants. The Anadarko system includes the Palo Duro system, which we acquired in March 2004.

- North Texas system: Includes approximately 4,200 miles of natural gas gathering pipelines and seven natural gas processing plants, including the additional natural gas gathering and processing assets we acquired for $164.6 million in January 2005.

- Our transportation operations include FERC-regulated natural gas interstate pipeline systems and non-FERC regulated natural gas intrastate pipeline systems. Our four major FERC regulated systems are the KPC pipeline, Midla pipeline, AlaTenn pipeline and UTOS pipeline. We also have a number of smaller non-regulated pipelines as well as trucking operations which are discussed below. Each of our pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers include marketers and large users of natural gas, such as power plants, industrial facilities and local distribution companies. Producers served by our systems consist of small, medium and large independent operators and large integrated energy companies. We sell NGLs resulting from our processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Our natural gas pipelines serve customers in the Gulf Coast and Mid-Continent regions of the United States. Customers include large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers.

Supply and Demand. Demand for our gathering, treating and processing services primarily depends upon the supply of natural gas reserves and the drilling rate of new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services also depends upon overall economic conditions and the prices of natural gas and NGLs. Three of our larger systems are located in basins that continue to experience growth in natural gas drilling and production.

Our East Texas system is primarily located in the East Texas Basin. While production from most regions within this basin has remained flat for several years, the Bossier trend within the East Texas Basin continues to experience substantial growth. The Bossier trend is located on the western side of our East Texas system. Production in the Bossier trend has grown from under 390 MMcf/d in 1997 to over 1,100 MMcf/d in 2005. In 2005, we completed construction of the 107-mile expansion of our East Texas system to provide customers with access to the Carthage Hub, an important outlet to major markets in the Midwest and Northeast United States. We expect the pipeline to be fully utilized with flows of 500 MMcf/d during the second quarter of 2006. We also commenced a significant expansion of treating and processing capacity in the region, a significant portion of which is already operational with the remaining facilities expected to be complete by mid-2006.

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale area within the Fort Worth Basin Conglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area is one of the most active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale area since the early 1980s, recent technological development in fracturing the shale formation allows commercial production of these natural gas reserves. Barnett Shale production has risen from approximately 110 MMcf/d to over 1,200 MMcf/d since 1999, with the drilling of over 3,800 wells. Growth in this region is expected for at least ten years.

Our Anadarko system is located within the Anadarko Basin. Within that basin, recent growth is occurring in the Granite Wash play, particularly in Hemphill and Wheeler Counties, Texas. We completed construction of our Zybach Processing Plant in the second quarter of 2005 and further expansion of this facility will be complete in early 2006. We initiated construction in late 2005 on a new 125 MMcf/d processing plant that is scheduled to be online in early 2006, which will accommodate expected volume growth from existing and future drilling activity.

We intend to expand our natural gas gathering and processing services primarily through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

Our natural gas pipelines generally serve different geographical areas, with differing supply and demand characteristics in each market. We believe that demand and competition for natural gas in the areas served by our natural gas assets generally will remain strong as a result of being located in areas where industrial, commercial or residential growth is occurring. The greatest demand for services in the markets served by our natural gas assets occurs in the winter months.

The table below indicates the capacity in MMcf/d of the transportation and wholesale customer pipelines with firm transportation contracts as of December 31, 2005 and the amount of capacity that is reserved under those contracts as of that date.

Major System	**Capacity MMcf/d**	**Percentage Reserved Under Contract as of December 31, 2005**
UTOS system	1,200	0 %
Midla system	200	74 %
AlaTenn system	200	40 %
KPC system	160	96 %
Bamagas system	450	61 %

Our UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term reserve capacity. The UTOS system s average daily throughput during 2005 was 158,000 MMBtu/d. The FERC has approved our negotiated settlement with UTOS shippers, keeping the current rates in effect through 2006.

Our Midla, AlaTenn and Bamagas systems primarily serve industrial corridors and power plants in Louisiana, Alabama and Tennessee. Industries in the area include energy intensive segments of the petrochemical and pulp and paper industries. The Bamagas system in northern Alabama serves two power plants and is contiguous with the AlaTenn system. We market the unused capacity on these systems under both short-term firm and interruptible transportation contracts and long-term firm transportation contracts. These systems are located in areas where opportunities exist to serve new industrial facilities and to make delivery interconnects to alleviate capacity constraints on other third-party pipeline systems. As of December 31, 2005, approximately 74% of contracted capacity of the Midla system is under contract to our marketing business.

Our KPC system has 82% of its capacity reserved under firm transportation contracts extending through 2009 and an additional 12% of its capacity reserved under contracts extending through 2017. The KPC system s primary customers are local distribution companies.

Our long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by our systems. Existing customers may not extend their contracts if the availability of natural gas from the Mid-continent and Gulf Coast producing regions was to decline and if the cost of transporting natural gas from other producing regions through other pipelines into the areas we serve were to render the delivered cost of natural gas uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Competition. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most natural gas producers and owners have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On the sour gas systems, such as our East Texas system, competition is more limited due to the infrastructure required to treat sour gas.

Competition for customers in the marketing of residue gas is based primarily upon the price of the delivered gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers/traders, chemical companies and other asset owners.

Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines.

Trucking Operations

We also include our trucking operations in our Natural Gas segment. Trucking operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads and treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, our trucking operations market these products. A key component of our business is ensuring market access for the liquids extracted at our processing facilities. On average this accounts for approximately 50% of the volume transported by our trucking business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, product treating and handling equipment and NGL storage facilities. In addition, our CO_2 plant, with 250 tons per day of capacity, takes excess CO_2 from hydrogen producers which we then sell to a variety of customers. At the end of 2004, we took 50% ownership of an underground propane storage facility in Petal, Mississippi, which augments the services we provide to our customers in the region. The total capacity of this facility is 5.6 million Bbls which increases our storage capabilities.

In late 2005, we began increasing our truck fleet by approximately 25 percent to meet the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as to capitalize on the opportunity to better serve our Gulf Coast customers.

Customers. Most of the customers of our trucking operations are wholesale customers, such as refineries and propane distributors. Our trucking operations also market products to wholesale customers such as petrochemical plants.

Supply and Demand. The areas served by our trucking operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for services is affected by the demand for NGLs and crude oil by large industrial refineries, and similar customers in the regions served by this business.

Competition. Our trucking operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of our trucking operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment s primary objective is to maximize the value of the gas purchased by our gathering systems and the throughput on our gathering and intrastate wholesale customer pipelines. To achieve this objective, our Marketing segment transacts with various counterparties to provide natural gas supply, transportation, balancing, storage and sales services.

Since our gathering and intrastate wholesale customer pipeline assets are geographically located within Texas, Oklahoma, Alabama and Louisiana, the majority of activities conducted by our Marketing segment are focused within these areas.

Customers. Natural gas purchased and sold by our Marketing segment is sold to industrial, utility and power plant end use customers. In addition, gas is sold to marketing companies at various market hubs. These sales are typically priced based upon a published daily or monthly price index. Sales to end-use customers incorporate a pass-through charge for costs of transportation and additional margin to compensate us for associated services.

Supply and Demand. Supply for our Marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our Natural Gas segment. Demand is typically driven by weather-related factors with respect to power plant and utility customers, and industrial demand.

Our Marketing business uses storage and the leasing of storage capacity to balance supply and demand factors within its portfolio. Marketing pays third-party storage facilities and pipelines for the right to store gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities. Due to the increased volumes from our gathering assets, our Marketing business leases third-party pipeline capacity downstream from our Natural Gas assets under firm transportation contracts following specific, controlled guidelines. This capacity is leased for various lengths of time and rates and allows our Marketing business to diversify its customer base by expanding its service territory and provides assurance that our gas will not be shut in due to capacity constraints on downstream pipelines.

Competition. Our Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and gas producers, independent aggregators and regional marketing companies.

REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The Lakehead, North Dakota, and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the ICA. As common carriers in interstate commerce, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA generally requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates we charge for service on our interstate common carrier pipelines. The ICA requires, among other things, that such rates be just and reasonable and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate the rates to determine if they are just and reasonable. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund with interest the increased revenues in excess of the amount that would have been collected during the term of the investigation at the rate properly determined to be lawful. The FERC also may investigate, upon complaint, or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the EP Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment, or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365 day period, to be just and reasonable under the ICA (i.e., grandfathered). The EP Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show, 1) that it was contractually barred from challenging the rates during the relevant 365 day period; 2) that there has been a substantial change after the date of enactment of the EP Act in the economic circumstances of the pipeline or in the nature of the services that were the basis for the rate; or 3) that the rate is unduly discriminatory or unduly preferential.

The FERC has determined that the Lakehead system rates are not covered by the grandfathering provisions of the EP Act because they were subject to challenge prior to the effective date of the statute. We believe that the rates for the North Dakota and Ozark systems should be found to be largely covered by the grandfathering provisions of the EP Act.

The EP Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for petroleum pipelines. Under the regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the pipeline s increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline s filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling, although a pipeline is not required to reduce its rate below the level grandfathered under the EP Act. Under Order No. 561, a pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

Under Order No. 561, the original inflation index adopted by the FERC was the annual change in the PPIFG minus one percentage point. The index was subject to review every five years. In 2000, the FERC again adopted the PPIFG index, but the FERC s rationale for doing so was overturned by the United States Court of Appeals for the District of Columbia Circuit on appeal. On remand, the FERC adopted an index of PPIFG without the minus one percentage point adjustment, and that result was upheld on appeal. As of 2005, the index remains the PPIFG with no adjustment. Based on the PPIFG for 2004, the index increased by 3.6288% for the year beginning July 1, 2005. The FERC has initiated another five-year review to determine the index to be in effect from 2006-2010. The FERC s initial proposal is that the index remains at the PPIFG with no adjustment. The Association of Oil Pipe Lines is seeking an index of the PPIFG plus 1.3 percentage points. The issue of the index to be adopted for the next five years remains undecided at this time.

Allowance for Income Taxes in Rates

In a 1995 decision involving our Lakehead system, which we refer to as the *Lakehead ruling*, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. A subsequent appeal of the *Lakehead ruling* was resolved by settlement and therefore was not adjudicated. In another FERC proceeding involving SFPP, the FERC initially relied on its previous *Lakehead ruling* to hold that SFPP could not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding appealed the FERC s orders to the United States Court of Appeals for the District of Columbia Circuit. On July 20, 2004, in *BP West Coast Products LLC v. FERC* (No. 99-1020), which we refer to as the *BP West Coast decision*, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding certain aspects of the FERC s orders regarding the SFPP case, but vacating the FERC s ruling regarding the proper tax allowance for SFPP. The United States Court of Appeals for the District of Columbia rejected the FERC s rationale for its *Lakehead ruling* and remanded the case to the FERC for further proceedings.

In the wake of the *BP West Coast* decision, the FERC initiated a notice and comment process to address tax allowance issues across a range of industries. We and many other companies commented on the proceeding. On May 4, 2005, the FERC issued a policy statement on income tax allowances, in which it reinstated its earlier policy of providing a full tax allowance on all partnership and similar legal interests in regulated companies if the owner of that interest has an actual or potential tax liability on the income earned through that interest. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. On December 16, 2005, FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16 order have been appealed to the D.C. Circuit, and rehearing requests have been filed with respect to the December 16 order. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service. Depending upon how the policy statement on income tax allowances is applied in practice to MLP pipelines, and whether it is ultimately upheld or modified on judicial review, could effect the tariffs of FERC-regulated pipelines.

A related issue is whether the FERC s income tax allowance policy can be relied upon by shippers as a substantial change in circumstances sufficient to remove the grandfathering protection under the EP Act from an oil pipeline s rates. The FERC determined in the SFPP case that its policy statement on income tax allowances does not represent a change from its pre-EP Act policy and therefore, cannot affect grandfathering of rates, a position that is still potentially subject to further judicial review.

The effect of the FERC s policy statement on income tax allowances on us is uncertain. The tariff rates on our common carrier interstate liquids pipelines have been established under a variety of different circumstances including settlements and tariff indexing. Since an income tax allowance is only one of many elements supporting our pipeline rates for service, we cannot predict with certainty what rates we will be allowed to charge in the future, or the potential impact on us of the FERC s policy statement on income tax allowances.

We believe that the rates we charge for transportation services on our interstate common carrier liquids pipelines are just and reasonable under the ICA. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Accounting for Pipeline Assessment Costs

In June 2005, the FERC issued an order in Docket AI05-1 describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation s Office of Pipeline Safety. The order takes effect beginning on January 1, 2006. Under the order, FERC-regulated companies are generally required to recognize costs incurred in performing pipeline assessments that are part of a pipeline integrity management program as maintenance expense in the period in which the costs are incurred. Costs for items such as rehabilitation projects designed to extend the useful life of the system can continue to be capitalized to the extent permitted under the existing rules. The FERC denied rehearing of its accounting guidance order on September 19, 2005.

We have historically capitalized first time in-line inspection programs, based on previous rulings by the FERC. Beginning in January 2006, we will prospectively account for pipeline assessment costs as maintenance expense for those systems applying SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. For non-SFAS No. 71 pipelines we will continue to capitalize first time crack-detection tool runs consistent with our prior practice; however, for regulatory reporting purposes these costs will be expensed by our FERC-regulated crude oil pipelines. Crack-detection tool runs address defects in construction or pipe manufacture that may not be readily evident at the time of construction. We will continue to expense other types of inspection tool runs as they primarily address conditions that develop from operations. Refer to Note 2: Summary of Significant Accounting Policies of our consolidated financial statements and Recent Accounting Developments in Management s Discussion and Analysis of Financial Condition and Results of Operations for additional discussion.

Regulation by the FERC of Interstate Natural Gas Pipelines

Our AlaTenn, Midla, KPC and UTOS systems are interstate natural gas pipelines regulated by the FERC under the NGA, and the NGPA. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides service to its customers. In addition, the FERC s authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- conduct and relationship with energy affiliates; and
- various other matters.

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the company voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

In November 2003, the FERC issued Order No. 2004 governing the Standards of Conduct for Transmission Providers (interstate pipelines). The new standards provide that interstate pipeline employees engaged in natural gas transmission system operations must function independently from any employees of their energy affiliates and marketing affiliates; and that an interstate pipeline must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially, an energy or marketing affiliate. Order 2004 restricts access to natural gas transmission customer data by marketing and other energy affiliates and provides certain conditions on service provided by interstate pipelines to their gas marketing and energy affiliates. We have implemented changes in business processes to comply with this order.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and Congress, especially in light of alleged market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce.

Intrastate Pipeline Regulation

Our intrastate liquids and natural gas pipeline operations generally are not subject to rate regulation by the FERC, but they are subject to regulation by various agencies of the states in which they are located. However, to the extent that our intrastate pipeline systems deliver natural gas into interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline making deliveries on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own certain natural gas pipelines that we believe meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to the FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but historically has not entailed rate regulation. Recently the FERC has initiated an inquiry regarding the extent to which gathering (both offshore and onshore) systems, particularly those that have been previously transferred from a regulated entity should be regulated by the FERC. Further, some states have or are considering providing greater regulatory scrutiny over the commercial regulation of natural gas gathering business. Many of the producing states have previously adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. During 2005 a notice of proposed rulemaking expanding federal safety regulation over portions of natural gas gathering systems was proposed. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids

The price at which we sell natural gas currently is not subject to federal or state regulation except for certain systems in Texas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations. Some of the FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action in a manner that is materially different than other natural gas marketers with whom we compete.

Our sales of crude oil, condensate and natural gas liquids currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC s jurisdiction under the ICA. Certain regulations implemented by the FERC in recent years could increase the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other marketers of these products.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and natural gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs and Rate Cases

Lakehead system

Under published tariffs at December 31, 2005 (including the tariff surcharges related to Lakehead system expansions) for transportation on the Lakehead system, the rates for transportation of light crude oil from Neche, North Dakota, where the System enters the United States (unless otherwise stated), to principal delivery points are set forth below.

	Published Tariff Per Barrel
To Clearbrook, Minnesota	$ 0.186
To Superior, Wisconsin	$ 0.363
To Chicago, Illinois area	$ 0.742
To Marysville, Michigan area	$ 0.888
To Buffalo, New York area	$ 0.909
Chicago to the international border near Marysville	$ 0.329

The rates at December 31, 2005 for medium and heavy crude oils are higher, and those for NGL s are lower than the rates set forth in the table to compensate us for differences in the costs of shipping different types and grades of liquid hydrocarbons. We periodically adjust our tariff rates as allowed under the FERC s indexing methodology and the tariff agreements described below.

The base portion of the rates for the Lakehead system are subject to the FERC s indexing mechanism and are adjusted annually to conform to the FERC index. Under the Settlement Agreement with CAPP that the FERC approved in 1996 and reconfirmed in 1998, we implemented a tariff surcharge related to the second phase of our SEP II project. This tariff surcharge, which is added to the base rates, is a cost-of-service based calculation that is trued-up annually (usually in April) for actual costs and throughputs from the previous calendar year, and is not subject to indexing. While the term of the 1996 settlement agreement has expired, we continue to abide by the spirit of the original agreement in our customer relationships.

Under the Tariff Agreement approved by the FERC in 1998, we also implemented a tariff surcharge for the Terrace expansion program of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago. On April 1, 2001, pursuant to an agreement between us and Enbridge Pipelines, our share of the surcharge was increased to $0.026 per barrel. This surcharge was in effect until April 1, 2004, when the surcharge to us changed to $0.007 per barrel. This $0.007 surcharge is expected to be in effect until 2010, after which time the surcharge will return to $0.013 per barrel through 2013, the term of the agreement. In addition to the Terrace surcharge, included in the 2005 tariff is the Terrace Schedule C adjustment. Under the tariff agreement, when Terrace Phase III facilities are in service, and annual actual average pumping exiting Clearbrook are less than 225,000 M3 per day, an adjustment is made to the Terrace surcharge. In 2005, this adjustment is $0.031 per barrel, based on annual actual average pumping exiting Clearbrook of 177,200 M3 per day in 2004.

On July 1, 2004, the FERC approved a settlement with CAPP involving a Facilities Surcharge mechanism, which allows for the recovery of costs for enhancements or modifications to the system at shipper request and approved by CAPP. The Facilities Surcharge permits the Lakehead system to recover the costs associated with particular shipper-requested projects through an incremental surcharge layered on top of the existing base rates and other FERC-approved surcharges already in effect. Like the SEP II surcharge, the Facilities Surcharge is a cost-of-service-based tariff mechanism that is trued-up each year for actual costs and throughput and, therefore, is not subject to adjustment either upwards or downwards under indexing. In 2005, the Facilities Surcharge was $0.007 per barrel for light movements from the U.S./Canada border near Neche, North Dakota to Chicago. The Facilities Surcharge currently includes four projects that were agreed to with CAPP in 2004. Additional projects to be included in the Facilities Surcharge will be determined as the result of a negotiating process between management of the Lakehead system and CAPP.

In late 2005, we reached agreement with CAPP on a tariff mechanism to recover the costs of the mainline expansion portion of the Southern Access project. As agreed by CAPP, the proposed surcharge is calculated using FERC Opinion 154-B methodology. The Opinion 154-B cost based surcharge is credited for incremental volumes utilizing the Lakehead system capacity in excess of the Lakehead system's Terrace configuration capacity. This is a customary regulatory principle and assures recovery by the pipeline of no more than its allowed rate of return on the Southern Access project. If no incremental volumes are moved on the capacity then the credit is generally zero, except as follows. The Southern Access project removes a System capacity bottleneck at Superior that otherwise limits the earnings potential of previous expansion projects such as the Terrace expansion. Consequently, a 50% revenue credit is provided if utilization of the Lakehead system capacity between Superior and Chicago is greater than the Lakehead system was otherwise capable of without the Southern Access project. This ex-Superior tolling mechanism is designed to share with our customers the benefits associated with the removal of the Terrace earnings limitation. On December 21, 2005, we filed an offer of settlement with the FERC seeking FERC approval for the Southern Access mainline expansion surcharge under the provisions of the previously approved Facilities Surcharge mechanism. The FERC will accept comments from shippers and other interested parties on the offer of settlement before determining whether to approve it. The FERC s ultimate decision on this surcharge is uncertain at this time, pending receipt of comments and any further proceedings that may occur in this docket. We have requested an expedited FERC decision on the offer of settlement. If the FERC fails to approve the proposed tariff mechanism for the Southern Access mainline expansion, or if it attached unacceptable conditions to such approval, that could have an adverse effect on our ability to proceed with the project or impact its timing.

Natural Gas Systems

Tariff rates on the FERC-regulated natural gas pipelines vary by pipeline and, in the case of KPC, by receipt point and delivery point. Competitive forces may prompt us to charge tariff rates below the FERC-approved ceiling rate on our interstate systems. The rates charged for transmission of natural gas on pipelines not regulated by the FERC, or a state agency, are established by competitive forces.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines and storage and processing facilities are subject to extensive federal and state environmental, operational and safety regulation. The added costs imposed by regulations are generally no different than those imposed on our competitors. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs.

Pipeline Safety and Transportation Regulation

Our transmission and non-rural gathering pipelines are subject to regulation by the DOT, under Title 49 United States Code (Pipeline Safety Act) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations, imposing direct mandates on operators of pipelines.

On December 17, 2002 the PSI Act of 2002 was enacted reauthorizing and amending the PSA in several important respects. Following requirements of mandates in the PSA, the DOT has issued regulations requiring operators of hazardous liquid and natural gas transmission pipelines subject to the regulations to assess, evaluate, repair and validate, through a comprehensive analysis, the integrity of pipeline segments that, in the event of a leak or failure, could affect a high consequence area. HCA s for liquid pipelines have been defined as: populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. For natural gas pipelines, HCA s are defined as segments in proximity to population density or places of public congregation.

The DOT has issued rules on requirements to submit maps, additional reports and enhance operator personnel qualification programs. We anticipate new rules regulating pipeline security, contractor drug testing, inspection, public awareness programs and annual information reporting. The 2002 amendments of the PSA also called for expanded regulations for qualification of workers performing safety-related tasks on pipelines, which we expect to be enacted by incorporation of an industry consensus standard currently under development. We have incorporated many of the anticipated new requirements into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material. Additionally, revised regulations are anticipated that may impose new federal mandates on certain non-DOT jurisdictional pipelines currently classified as rural gathering lines. Pending specific proposed regulations, we are not certain of the effect or costs that the new requirements may have on our operations.

Various states in which we operate have authority to issue additional regulations affecting intrastate or gathering pipeline design, safety and operational requirements. In particular, during 2003 the State of Oklahoma passed legislation affecting gathering pipeline business activities and in early 2005, the State of Texas proposed new legislation that could, if passed, increase the commercial regulation of gathering pipelines. We are not certain of the effect that passage of the final legislation, or any of the legislation will have on our business operations or costs.

Our trucking and railcar operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials.

We believe that our pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, we have taken actions to remediate the situations. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

Pressure Restrictions on the Lakehead system

Following a leak that occurred on our Lakehead system in July 2002, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA, formerly the OPS) imposed pressure restrictions on the entire line that was affected. At the time, we proposed a return-to-service plan, which included implementing certain internal inspections and other strategies to verify the integrity of the pipeline in the affected area. During 2003, the PHMSA removed a majority of the restrictions, while directing that a small restriction remain in place in one area of the line in Minnesota. PHMSA has indicated that this restriction is expected to be removed following another internal inspection and associated pipeline rehabilitation expenditures to be concluded in 2006, evaluation of the interim performance of the line and assessment of our progress in implementing our risk management plan.

Environmental Regulation

General. *Our operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position since the operations of our competitors are generally similarly affected.*

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with our operations, such as leaks or spills of crude oil, liquids or natural gas or other substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines, penalties, or damages for related violations of environmental laws or regulations.

Although we are entitled, in certain circumstances, to indemnification from third parties for environmental liabilities relating to assets we acquired from those parties, these contractual indemnification rights are limited and, accordingly, we may be required to bear substantial environmental expenses. However, we believe that through our due diligence process, we identify and manage substantial issues.

Air and Water Emissions. Our operations are subject to the federal Clean Air Act and the federal Clean Water Act and comparable state and local statutes. We anticipate, therefore, that we will incur certain capital expenses in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities.

An operating permit excursion occurred at our Bryans Mill Treating Plant in 2003 where a significant amount (approximately 7,000 tons) of sulfur-dioxide (SO_2) was released above permit limits. We self-reported the incident to the applicable state agency. We found a plant catalyst bed to be deficient and corrected the problem. We have augmented our administrative reporting systems and operations procedures to prevent future occurrences. In 2005 an administrative penalty of $68,158 was issued by the state in the form of an Agreed Order which we accepted.

The Oil Pollution Act (OPA) was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of our non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. For our liquid pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For our non-transportation facilities, such as storage tanks that are not integral to pipeline transportation system, the OPA regulations are promulgated by the EPA. We believe we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The federal CERCLA (also known as the Superfund law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. We may generate some wastes that fall within the definition of a hazardous substance. We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for material cleanup costs under CERCLA or similar state laws.

Employee Health and Safety. The workplaces associated with our operations are subject to the requirements of the federal OSHA and comparable state statutes that regulate worker health and safety. We have an ongoing safety, procedure and training program for our employees and believe that our operations are in compliance with applicable occupational health and safety requirements, including industry consensus standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Site Remediation. We own and operate a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process crude oil, natural gas and other petroleum products. Many of our facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, RCRA and analogous state laws as described above.

Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for us, could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable government agencies where appropriate.

In connection with our acquisition of the Midcoast system from Enbridge, the General Partner agreed to indemnify us and other related persons for certain environmental liabilities of which the General Partner had knowledge. Pursuant to the contribution agreement related to this acquisition, the General Partner will not be required to indemnify us until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner s aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. We will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed under the contribution agreement between the General Partner and us. In addition, we will be liable for all removal, remediation and disposal of all asbestos containing materials and all naturally occurring radioactive materials associated with the Northeast Texas system and for which the General Partner is liable to the prior owner of that system.

Although we believe these indemnities and conditions provide valuable protection, it is possible that the sellers from whom these assets were purchased will not be able to satisfy their indemnity obligations or their remedial obligations related to retained liabilities or properties. In this case, it is possible that governmental agencies or third party claimants could assert that we may be liable or bear some responsibility for such obligations.

EMPLOYEES

Neither we nor Enbridge Management, has any employees. Our general partner has delegated to Enbridge Management, pursuant to a delegation of control agreement, substantially all of the responsibility for our day-to-day management and operation. Our general partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel, who act on Enbridge Management s behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, treating, processing and transportation industry. We maintain insurance coverage for our operations and properties considered to be customary in the industry. There can be no assurance, however, that insurance coverage we maintain will be available or adequate for any particular risk or loss, or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

CAPITAL EXPENDITURES

In 2005, we made capital expenditures of $344.8 million, of which $311.8 million was for pipeline system enhancements, and $33.0 million for core maintenance. See also Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Investing Activities.

TAXATION

For U.S. federal and state income tax purposes, we are not a taxable entity. Federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. Such taxable income may vary substantially from net income reported in our consolidated statements of income.

AVAILABLE INFORMATION

We file annual, quarterly and other reports, and any amendments to those reports, and information with the SEC under the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including ours.

We also makes available free of charge on or through our Internet website *http://www.enbridgepartners.com* our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not part of this report.

Item 1A. Risk Factors

We encourage you to read the risk factors below in connection with the other sections of this Annual Report on Form 10-K.

Risks Related to Our Business

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our pipeline systems. Decreases in the volumes transported by our systems, whether caused by supply or demand factors in the markets these systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

The volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Crude oil deliveries on our Lakehead system have declined from the prior year in each of the last three calendar years, because of decreases in conventional crude oil exploration and production activities in western Canada and other factors including supply disruption and competition. In January 2005, deliveries on our Lakehead system were impacted by a fire at a Suncor facility. The volume of crude oil that we transport on the Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the delivery by others of crude oil and refined products into these regions and the Province of Ontario. Pipeline capacity for the delivery of crude oil to the Great Lakes and Midwest regions of the United States currently exceeds refining capacity.

In addition, our ability to increase deliveries to expand the Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta, Canada. Furthermore, full utilization of additional capacity as a result of our current and future expansions of the Lakehead system, including the Terrace expansion program, will largely depend on these anticipated increases in crude oil production from oil sands projects.

The volume of shipments on natural gas systems depends on the supply of natural gas and NGLs available for shipment on those systems from the producing regions that supply these systems. Volumes shipped on these systems also are affected by the demand for natural gas and NGLs in the markets these systems serve. Existing customers may not extend their contracts if the availability of natural gas from the Mid-Continent, Gulf Coast and East Texas producing regions was to decline or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by the natural gas systems was to render the delivered cost of natural gas on our systems uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Changes in our tariff rates or challenges to our tariff rates could have a material adverse effect on our financial condition and results of operations; a recent FERC Policy Statement that limited allowances for income tax in an unrelated pipeline s cost of service, if applied to our FERC-regulated systems, could adversely affect our rates.

The tariff rates charged by several of our existing pipeline systems are regulated by the FERC, or various state regulatory agencies. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, the profitability of our pipeline businesses might suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which delay could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically propose and implement new rules and regulations, terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the tariff rates charged for our services. Several states, including Oklahoma and Texas, are taking a more active role in the rate and service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

The question of whether and to what extent an income tax allowance should be included in a regulated utility s cost of service for rate-making purposes was a matter of uncertainty for a number of years. In a 2004 decision involving an oil pipeline limited partnership, *BP West Coast, LLC v. FERC*, a United States Court of Appeals for the District of Columbia Circuit vacated the FERC s policy that allowed an oil pipeline limited partnership to include in its costs of service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In its Policy Statement on Income Tax Allowances issued on May 4, 2005, the FERC concluded that it would permit an income tax allowance for all entities or individuals owning public utility assets, provided that such entities or individuals have an actual or potential income tax liability on the public utility income. The burden is on the entity seeking the income tax allowance in a specific rate proceeding to establish that its partners have an actual or potential income tax obligation on the entity s public utility income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. On December 16, 2005, FERC issued its first case-specific oil pipeline review of the income tax allowance issue in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. Further, in the December 16 order, FERC concluded that for tax allowance purposes, FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal tax rate of 28%. The new tax allowance policy as applied to the *BP West Coast* decision is subject to rehearing and possible further action by the United States Court of Appeals for the District of Columbia Circuit or another court on appeal. Further, application of the FERC s policy statement in individual cases may be subject to further FERC action or review in the appropriate Court of Appeals. The ultimate outcome of these proceedings, therefore, is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service. If we were to file for a cost of service-based rate increase, we would be subject to FERC s new policy and potential challenges of that policy. On our Lakehead system, base rates are subject to the FERC indexing mechanism consistent with our expired settlement agreement and are not currently affected by the tax allowance policy. However, the original base rates calculated in accordance with the Settlement Agreement employed a lower tax allowance than provided for by the new policy. Were the Lakehead system, or any of our FERC regulated systems, subject to a cost-of-service regulatory proceeding in the future, the tax allowance issue would be one of the many factors which would affect the resulting rates.

Competition may reduce our revenues.

Our Lakehead system faces current, and potentially further competition for transporting western Canadian crude oil from other pipelines, which may reduce its revenues. Our Lakehead system competes with other crude oil and refined product pipelines and other methods of delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Minnesota; Chicago, Illinois; Detroit, Michigan; Toledo, Ohio; Buffalo, New York; and Sarnia, Ontario and the refinery market and pipeline hub located in the Patoka/Wood River area of southern Illinois. Refineries in the markets served by our Lakehead system compete with refineries in western Canada, the Province of Ontario and the Rocky Mountain region of the United States for supplies of western Canadian crude oil.

Our Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

We also encounter competition in our natural gas gathering, treating, processing and transmission businesses. Many of the large wholesale customers served by our systems transmission and wholesale customer pipelines have multiple pipelines connected or adjacent to their facilities. Thus, many of these wholesale customers have the ability to purchase natural gas directly from a number of pipelines and/or from third parties that may hold capacity on other pipelines. Likewise, most natural gas producers and owners have alternate gathering and processing facilities available to them. In addition, they have other alternatives, such as building their own gathering facilities or, in some cases, selling their natural gas supplies without processing. Some of our natural gas marketing competitors have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do.

Competition with Enbridge may reduce our revenues.

Enbridge has agreed with us that, so long as an affiliate of Enbridge is our general partner, Enbridge and its subsidiaries may not engage in or acquire any business that is in direct material competition with our businesses, subject to the following exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;

- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;

- Enbridge and its subsidiaries are not prohibited from acquiring any competitive business as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge s reasonable judgment, is not attributable to the competitive business; and

- Enbridge and its subsidiaries are not prohibited from acquiring any competitive business if that business is first offered for acquisition to us and we fail to approve, after submission to a vote of unitholders, the making of the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system even if such transportation is in direct material competition with our business.

This agreement also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario, Canada market. This competition from Enbridge has reduced our deliveries of crude oil to Ontario.

Our gas marketing operations involve market and certain regulatory risks.

As part of our natural gas marketing activities, we purchase natural gas at prices determined by prevailing market conditions. Following our purchase of natural gas, we generally resell natural gas at a higher price under a sales contract that is generally comparable in terms to our purchase contract, including any price escalation provisions. The profitability of our natural gas operations may be affected by the following factors:

- our ability to negotiate on a timely basis natural gas purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers willingness to use other fuels when natural gas prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results;
- the ability of our customers to make timely payment;
- inability to match purchase and sale of natural gas on comparable terms; and
- changes in, limitiations upon, or elimination of the regulatory authorization required for our wholesale sales of natural gas in interstate commerce.

Our results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

We buy and sell natural gas and NGLs in connection with our marketing activities. Commodity price exposure is also inherent in gas purchase and resale activities and in gas processing. To the extent that we engage in hedging activities to reduce our commodity price exposure, we may be prevented from realizing the full benefits of price increases above the level of the hedges. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under such contracts. In addition certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earning volatility due to turbulent commodity prices.

Compliance with environmental and operational safety regulations, including any remediation of soil or water pollution or hydrostatic testing of our pipeline systems, may increase our costs and/or reduce our revenues.

Our pipeline, gathering, processing and trucking operations are subject to federal, state and local laws and regulations relating to environmental protection and operational and worker safety. Liquid petroleum and natural gas transportation and processing operations always involve the risk of costs or liabilities or operational modifications related to regulatory compliance as well as resulting from historical

environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents. As a result, we may incur costs or liabilities of this type, or experience a reduction in revenues, in the future. We may also incur costs in the future due to changes in environmental and safety laws and regulations, enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher tariffs.

Failure of pipeline operations due to unforeseen interruptions or catastrophic events may adversely affect our business and financial condition.

Operation of complex pipeline systems, gathering, treating, processing and trucking operations involves many risks, hazards and uncertainties, such as operational hazards and unforeseen interruptions caused by events beyond our control. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. A casualty occurrence might result in injury or loss of life or extensive property or environmental damage for which we may bear a part or all of the cost.

Our acquisition strategy may be unsuccessful if we incorrectly predict operating results, are unable to identify and complete future acquisitions and integrate acquired assets or businesses or are unable to raise financing on acceptable terms.

The acquisition of complementary energy delivery assets is a component of our strategy. Acquisitions present various risks and challenges, including:

- the risk of incorrect assumptions regarding the future results of the acquired operations or expected cost reductions or other synergies expected to be realized as a result of acquiring such operations;
- the risk of failing to effectively integrate the operations or management of acquired assets or businesses or a significant delay in such integration; and
- diversion of management s attention from existing operations.

In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future or be unable to raise, on terms we find acceptable, any debt or equity financing that may be required for any such acquisition.

Our actual construction and development costs could exceed our forecast and our cash flow from construction and development projects may not be immediate which may limit our ability to increase cash distributions.

Our strategy contemplates significant expenditures for the development, construction or other acquisitions of energy infrastructure assets. Increased demand for the steel used to fabricate the pipe needed for our construction projects and increased competition for labor has resulted in increased costs for these resources. As a result, we may not be able to complete our projects at the costs currently estimated or within the time periods we have projected. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional debt or equity.

Any or all of these methods may not be available when needed or may adversely affect our future results operations and cash flows.

Our revenues and cash flows may not increase immediately on our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, or other factors, we may not meet our obligations as they become due and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Oil measurement losses on the Lakehead system can be materially impacted by changes in estimation, commodity prices and other factors.

Oil measurement losses occur as part of the normal operating conditions associated with our liquid petroleum pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;

- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and

- revaluation losses, which are a function of crude oil prices and the level of the carrier s inventory.

There are inherent difficulties in quantifying oil measurement losses because physical measurements of volumes are not practical due to the fact that products constantly move through the pipeline and virtually all of the pipeline system is located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the length of the Lakehead system and the number of different grades of crude oil and types of crude oil products it carries. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

The interests of Enbridge may differ from our interests and the interests of our securityholders, and the board of directors of Enbridge Management may consider the interests of all parties to a conflict, not just the interests of our securityholders, in making important business decisions.

Enbridge indirectly owns all of the stock of our general partner and all of the voting stock of Enbridge Management, and elects all of the directors of both companies. Furthermore, some of the directors and officers of our general partners and Enbridge Management are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between our unitholders and Enbridge.

Our partnership agreement limits the fiduciary duties of our general partner to our unitholders. These restrictions allow our general partner to resolve conflicts of interest by considering the interests of all of the parties to the conflict, including Enbridge Management s interests, our interests and those of our general partner. In addition, these limitations reduce the rights of our unitholders under our partnership agreement to sue our general partner or Enbridge Management, its delegee, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

We do not have any employees. In managing our business and affairs, we will rely on employees of Enbridge, and its affiliates, who will act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

We are exposed to credit risks of some of our customers

Our Bamagas system has agreements to provide transportation of up to 276,000 MMBtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation. The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. Calpine has recently declared bankruptcy and is in reorganization. Although we fully expect our customer to continue to meet its obligations to us under the terms of the transportation agreements, we are exposed to a potential asset impairment of up to $55 million, representing the book value of the pipeline, if the customer is unable to fulfill its commitments. We are actively monitoring Calpine s bankruptcy and are evaluating alternate uses for the system.

As a result of the widespread damage caused by hurricanes Katrina and Rita, the major credit rating agencies have issued negative credit implications for several of our industrial and utility customers. Although we do not anticipate any significant deterioration in the credit standing of these customers, we continue to monitor their financial condition and expect improvement in their credit standing as system outages are restored and property damage repaired.

Canada s ratification of the Kyoto Protocol may adversely impact our operations.

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. We and Enbridge are monitoring the Canadian federal government s approach to implementation. While the United States is not a signatory to the Kyoto Protocol, other environmental protection initiatives have been implemented regulating certain priority pollutants. During 2005, a proposed revision to the U.S. Energy Act was offered that would have, if it had passed, expanded the regulation of certain greenhouse gas emissions requiring a cap and establishing a trade to facilitate compliance. The provision would have made natural gas pipelines the segment of the gas industry regulated by such an amendment. While this legislation did not pass in 2005, another proposal has been offered by the U.S. Congress early in 2006. While the outcome is uncertain at this time, if the provision passes, the Partnership could be subject to additional costs to monitor and control emissions above and beyond current practices and permits.

Risks arising from Our Partnership Structure and Relationships with Our General Partner and Enbridge Management

We can issue additional common or other classes of units, including additional i-units to Enbridge Management when it issues additional shares, which would dilute your ownership interest.

The issuance of additional common or other classes of units by us, including the issuance of additional i-units to Enbridge Management when it issues additional shares, other than our quarterly distributions to you, may have the following effects:

- the amount available for distributions on each unit may decrease;
- the relative voting power of each previously outstanding unit may decrease; and
- the market price of the Class A common units may decline.

Additionally, the public sale by our general partner of a significant portion of the Class B common units that it currently owns could reduce the market price of the Class A common units. Our partnership agreement allows the general partner to cause us to register for public sale any units held by the general partner or its affiliates. A public or private sale of the Class B common units currently held by our general partner could absorb some of the trading market demand for the outstanding Class A common units.

We are a holding company and depend entirely on our operating subsidiaries distributions to service our debt obligations.

We are a holding company with no material operations. If we cannot receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions, which could further limit each operating subsidiary s ability to make distributions to us.

The debt securities we issue and any guarantees issued by the Subsidiary Guarantors will be structurally subordinated to the claims of the creditors of any of our operating subsidiaries who are not guarantors of the debt securities. Holders of the debt securities will not be creditors of our operating subsidiaries who have not guaranteed the debt securities. The claims to the assets of these non-guarantor operating subsidiaries derive from our own ownership interest in those operating subsidiaries. Claims of our non-guarantor operating subsidiaries creditors will generally have priority as to the assets of such operating subsidiaries over our own ownership interest claims and will therefore have priority over the holders of our debt, including the debt securities. Our non-guarantor operating subsidiaries creditors may include:

- general creditors;
- trade creditors;
- secured creditors;
- taxing authorities; and
- creditors holding guarantees.

Enbridge Management s discretion in establishing our cash reserves gives it the ability to reduce the amount of cash available for distribution to our unitholders.

Enbridge Management may establish cash reserves for us that in its reasonable discretion are necessary to fund our future operating and capital expenditures, provide for the proper conduct of business, comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to our holders of common units.

Risks Related to Our Debt and Our Ability to Distribute Cash

Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A Common Units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility.

Our primary operating subsidiary is prohibited by its first mortgage notes from making distributions to us, and we are prohibited by our credit facility from making distributions to our unitholders, if a default exists under the respective governing agreements. In addition, the agreements governing our credit facility and our subsidiary s first mortgage notes may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of assets and to

incur liens to secure debt. A breach of any restriction under our credit facility or our indentures or our subsidiary s first mortgage notes could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of the credit facility, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

Tax Risks to Common Unitholders

We may be classified as an association taxable as a corporation rather than as a partnership, which would substantially reduce the value of our Class A common units.

We could be treated as a corporation for United States income tax purposes. Our treatment as a corporation would substantially reduce the cash distributions on the common units that we distribute quarterly. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities. The anticipated benefit of an investment in our common units depends largely on the treatment of us as a partnership for federal income tax purposes. Under current law, we are treated as a partnership for federal income tax purposes and do not pay any federal income tax at the entity level. In order to qualify for this treatment, we must derive more than 90% of our annual gross income from specified investments and activities. While we believe that we currently do qualify and intend to meet this income requirement, we may not find it possible, regardless of our efforts, to meet this income requirement or may inadvertently fail to meet this income requirement. Current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would pay state income taxes at varying rates. Under current law, distributions to unitholders would generally be taxed as a corporate distribution. Because a tax would be imposed upon us as a corporation, the cash available for distribution to a unitholder would be substantially reduced. Treatment of us as a corporation would cause a substantial reduction in the value of our units.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. State tax legislation resulting in the imposition of a partnership-level income tax on us would reduce the cash distributions on the common units and the value of the i-units that we will distribute quarterly to Enbridge Management. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our units.

If the Internal Revenue Service does not respect our curative tax allocations, the after-tax return to our unitholders on their investment in our Class A common units would be adversely affected.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any Class A common units. If the Internal Revenue Service, which we refer to as the IRS, does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A common units will be materially higher than previously estimated

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A common units.

The holders of our Class A common units will be required to pay United States federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. They will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income. Further, if we have a large amount of nonrecourse liabilities, they may incur a tax liability that is greater than the money they receive when they sell their Class A common units.

A unitholder may be required to file tax returns with and pay income taxes to the states where we or our subsidiaries own property and conduct business.

In some cases, a unitholder may be required to file income tax returns with and pay income taxes to the states in which we or our subsidiaries own property and conduct business, which are currently Alabama, Alaska, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, South Carolina, North Carolina, North Dakota, Oklahoma, Tennessee, Texas and Wisconsin. In the future, we may acquire property or do business in other states or in foreign jurisdictions. In addition to tax liabilities to such state and foreign jurisdictions, the owner of a Class A common unit may also incur tax and filing responsibilities to localities within such jurisdictions.

Ownership of Class A common units raises issues for tax-exempt entities and other investors.

An investment in our Class A common units by tax-exempt entities, including employee benefit plans, individual retirement accounts, Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. Virtually all of the income derived from our Class A common units by a tax-exempt entity will be unrelated business taxable income and will be taxable to the tax-exempt entity. Additionally, no significant part of our gross income will be considered qualifying income for purposes of determining whether a unitholder qualifies as a regulated investment company for its tax years beginning on or prior to October 22, 2004 (before the American Jobs Creation Act of 2004). Further, a unitholder who is a nonresident alien, a foreign corporation or other foreign person will be required to file a federal income tax return and pay tax on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of a Class A common unit.

Our registration with the Secretary of the Treasury as a tax shelter may increase your risk of an IRS audit.

Because we are a registered tax shelter with the Secretary of the Treasury, a unitholder may face an increased risk of an IRS audit resulting in taxes payable on our income as well as income not related to us. We could be audited by the IRS and adjustments to our income or losses could be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax and audit process. Further, any adjustments in our tax returns will lead to adjustments in the unitholders tax returns and may lead to audits of unitholders tax returns and adjustments of items unrelated to us. Each unitholder is responsible for any tax owed as the result of an examination of their personal tax return.

Our treatment of a purchaser of Class A common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of the Class A common units.

Because we cannot match transferors and transferees of Class A common units, we are required to maintain the uniformity of the economic and tax characteristics of these units in the hands of the purchasers and sellers of these units. We do so by adopting certain depreciation conventions that do not conform with all aspects of the United States Treasury regulations. An IRS challenge to these conventions could adversely affect the tax benefits to a unitholder of ownership of the Class A common units and could have a negative impact on their value.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We currently conduct business and/or own properties located in 23 states: Alabama, Alaska, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, North Carolina, North Dakota, Oklahoma, South Carolina, Texas, Tennessee and Wisconsin. In general, our systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities. The pumping stations, tanks, terminals and certain other facilities of our systems are located on land that is owned by us, except for five pumping stations that are situated on land owned by others and used by us under easements or permits.

Substantially all of our Lakehead system assets are subject to a first mortgage lien collateralizing indebtedness of our Lakehead Partnership.

Titles to our properties acquired in the Midcoast system acquisition are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2005.

PART II

Item 5. Market for Registrant s Common Equity and Related Unitholder Matters

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol EEP. The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2005 and 2004 are summarized as follows:

	First	Second	Third	Fourth
2005 Quarters				
High	$ 55.66	$ 54.32	$ 57.08	$ 55.99
Low	$ 47.90	$ 48.75	$ 50.40	$ 42.00
Cash distributions paid	$ 0.925	$ 0.925	$ 0.925	$ 0.925
2004 Quarters				
High	$ 51.33	$ 51.95	$ 49.75	$ 51.90
Low	$ 47.71	$ 41.35	$ 46.22	$ 45.60
Cash distributions paid	$ 0.925	$ 0.925	$ 0.925	$ 0.925

On February 17, 2006, the last reported sales price of our Class A common units on the NYSE was $45.55. At February 17, 2006, there were approximately 78,000 Class A common unitholders, of which there were approximately 2,000 registered Class A common unitholders of record. There is no established public trading market for our Class B common units, all of which are held by the General Partner, or our i-units, all of which are held by Enbridge Management.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived, and should be read in conjunction with, our audited consolidated financial statements and notes thereto beginning at page F-1. See also Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
	(dollars in millions, except per unit amounts)				
Income Statement Data:(2)					
Operating revenue	$ 6,476.9	$ 4,291.7	$ 3,172.3	$ 1,185.5	$ 342.3
Operating expenses	6,285.0	4,054.5	2,978.0	1,047.5	244.5
Operating income	191.9	237.2	194.3	138.0	97.8
Interest expense	(107.7)	(88.4)	(85.0)	(59.2)	(59.3)
Rate refunds		(13.6)			
Other income (expense)	5.0	3.0	2.4	(0.2)	0.9
Minority interest				(0.5)	(0.5)
Net income	$ 89.2	$ 138.2	$ 111.7	$ 78.1	$ 38.9
Net income per common and i-unit(1)	$ 1.06	$ 2.06	$ 1.93	$ 1.76	$ 0.98
Cash distributions paid per unit	$ 3.70	$ 3.70	$ 3.70	$ 3.60	$ 3.50
Financial Position Data (at year end):(2)					
Property, plant and equipment, net	$ 3,080.0	$ 2,778.0	$ 2,465.6	$ 2,253.3	$ 1,486.6
Total assets	4,428.4	3,770.7	3,231.8	2,834.9	1,649.2
Long-term debt, excluding current maturities(3)	1,682.9	1,559.4	1,155.8	1,011.4	715.4
Loans from General Partner and affiliates	151.8	142.1	133.1	444.1	176.2
Partners capital:					
Class A common units(4)	1,142.4	1,021.6	914.9	604.8	577.0
Class B common units	67.2	66.7	64.2	48.7	48.8
i-units(5)	421.7	399.4	370.7	335.6	
General Partner	34.6	31.0	27.5	18.8	6.5
Accumulated other comprehensive (loss) income	(302.1)	(120.8)	(64.0)	(16.3)	11.9
Partners capital	$ 1,363.8	$ 1,397.9	$ 1,313.3	$ 991.6	$ 644.2
Cash Flow Data:					
Cash flows provided by operating activities	$ 267.1	$ 245.4	$ 148.2	$ 200.8	$ 125.3
Cash flows used in investing activities	(437.1)	(419.1)	(431.0)	(557.2)	(302.1)
Cash flows provided by financing activities	181.5	187.6	286.9	376.5	179.8
Acquisitions and capital expenditures included in investing activities, net of cash acquired	(531.2)	(429.8)	(423.5)	(563.9)	(300.0)

Notes to Selected Financial Data Table

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating net income per unit: 2005, $23.5 million; 2004, $22.5 million; 2003, $19.6 million; 2002, $13.1 million; and 2001, $9.1 million.

(2) Our income statement and financial position data reflect the following acquisitions and dispositions:

- December 2005, disposition of assets on the East Texas and South Texas systems;
- January 2005, acquisition of the natural gas gathering and processing asset in north Texas;
- March 2004 acquisition of the Mid-Continent system;
- December 2003 acquisition of the North Texas system;
- October 2002 acquisition of the Midcoast system including natural gas gathering and transmission pipelines, and natural gas treating and processing assets in the Mid-continent and Gulf Coast regions of the United States;
- November 2001 acquisition of the natural gas gathering, transportation, processing and marketing assets in east Texas; and
- May 2001 acquisition of Enbridge Pipelines (North Dakota) L.L.C.

(3) Our income statement, financial position and cash flow data include the effect of:

- The September 2005 amendment of our credit facility to extend the letter of credit sub limit from $175 million to $300 million and increase the commitments available from $600 million to $800 million maturing in 2010;
- The April 2005 establishment of a $600 million commercial paper program;
- The December 2004 issuance of $300 million of senior unsecured notes;
- The April 2004 amendment of our credit facilities to terminate the 364-day revolving credit facility and increase the Three-year term credit facility to $600 million maturing in 2007;
- The January 2004 issuance of $200 million of senior unsecured notes;
- The May 2003 issuance of $400 million of senior unsecured notes; and
- January 2002 replacement of the $350 million Revolving Credit Facility with a $300 million Three-year term credit facility and a $300 million 364-day Facility.

(4) Our income statement, financial position and cash flow data include the effect of the following common unit issuances:

- 0.13 million Class A common units in December 2005; 3.0 million Class A common units in November 2005; 2.5 millon Class A common units in February 2005;
- 3.68 million Class A common units in September 2004; 0.45 million Class A common units in January 2004;
- 5.0 million Class A common units in December 2003; 3.9 million Class A common units in May 2003;

- 2.3 million Class A common units in March 2002;
- 2.3 million Class A common units in November 2001; and 1.8 million Class A common units in May 2001.

(5) Reflects the issuance of 9.0 million i-units in October 2002 and subsequent quarterly i-unit distributions of 0.8 million, 0.8 million, 0.8 million and 0.2 million during 2005, 2004, 2003 and 2002, respectively, in lieu of cash distributions.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our Consolidated Financial Statements and the accompanying notes beginning on page F-1 of this Annual Report on Form 10-K.

RESULTS OF OPERATIONS OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and NGLs through pipelines and related facilities; and
- Providing supply, transportation and sales service, including purchasing and selling of natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. Each of these systems largely consist of FERC-regulated interstate crude oil and liquid petroleum pipelines. Our Mid-Continent system is also one of the largest above ground crude oil storage facilities in North America, with the majority of the capacity available for merchant storage not subject to regulation by the FERC. Each of these systems generates most of its revenues by charging shippers a per barrel tariff rate to transport and store crude oil and liquid petroleum.

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, including four FERC-regulated interstate natural gas transmission pipelines, as well as natural gas treating and processing plants and related facilities. The revenues of our Natural Gas segment are derived from the fees we charge to gather and process natural gas and the rates we charge to transport natural gas on our pipelines.

Our Marketing segment provides supply, transmission, storage and sales services to producers and wholesale customers on our gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Our Marketing activities are primarily undertaken to realize incremental revenue on gas purchased at the wellhead, increase pipeline utilization and provide other services that are valued by our customers.

Several types of arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide, or where we purchase natural gas or NGLs. We employ derivative financial instruments to reduce our exposure to natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of SFAS No. 133, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative financial instrument and the associated physical transaction.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31:

	2005	2004	2003
	(in millions)		
Operating Income			
Liquids	$ 127.3	$ 139.1	$ 124.5
Natural Gas	110.5	98.1	63.6
Marketing	(42.4)	3.6	9.4
Corporate, operating and administrative	(3.5)	(3.6)	(3.2)
Total Operating Income	191.9	237.2	194.3
Interest expense	(107.7)	(88.4)	(85.0)
Rate refunds		(13.6)	
Other income	5.0	3.0	2.4
Net Income (Loss)	$ 89.2	$ 138.2	$ 111.7

Summary Analysis of Operating Results

Liquids

Our Liquids segment contributed operating income of $127.3 million in 2005, or $11.8 million less than the $139.1 million contributed in 2004. The operating income of our Liquids segment in 2005 was affected by the following factors:

- Deliveries on our Lakehead system declined by approximately 83,000 Bpd primarily due to a fire in January 2005 at an upgrader site owned by Suncor, an oil sands producer in Alberta, Canada. A heavier crude oil mix and the annual index adjustment to our tariff rates generated additional revenue as did the full year contribution from our Mid-Continent assets, more than offsetting the loss of revenue resulting from the lower transportation volumes on our Lakehead system.

- Higher workforce-related costs resulting from increases in pension and healthcare costs passed through to us and other general and administrative cost increases.

- Increased costs for the additional two months of ownership of our Mid-Continent system assets in 2005 compared with 2004.

Natural Gas

Operating income from our Natural Gas segment grew to $110.5 million in 2005 representing an increase of $12.4 million over the $98.1 million generated in 2004. The increased contribution of our Natural Gas segment is attributable to the following:

- Average daily volume on our major natural gas systems was 17 percent greater in 2005 than in 2004, partially due to historically high natural gas prices, which encourage producers to generate and ship greater volumes of natural gas and NGL. Also contributing to the volume growth were the gathering and processing assets in north Texas we acquired in January 2005, and the addition of 500 MMcf/d of natural gas transportation capacity on our East Texas system from our late-June 2005 completion of the 107-mile natural gas pipeline to the Carthage, Texas market hub.

- Operating income of our natural gas segment was also positively affected by a gain of $18.1 million we realized on the sale of gathering and processing assets located in our East and South Texas systems. These gains were mostly offset by $16.3 million of losses we realized from the settlement of natural gas derivatives in connection with the sale. We had previously recorded unrealized losses associated with this natural gas derivative that were realized upon settlement.

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- Keep-whole processing arrangements contributed to improved results. Two factors contributed to this increase, first NGL prices increased in relation to the cost of our natural gas feedstocks. Second, additional processing capacity was commissioned in 2005. In combination, these factors resulted in an increase of $11.8 million in revenue less cost of natural gas.

- The operating results of our Natural gas segment were negatively affected by unrealized non-cash mark-to-market losses of $8.1 million associated with derivative financial instruments that do not qualify for hedge accounting under SFAS No. 133 and ineffectiveness charges associated with hedges that qualify for cash flow hedge accounting under SFAS No. 133.

- Operating income of our Natural gas segment in 2005 included an increase of $36.7 million in operating and administrative costs from 2004. The increase is attributable to increases in workforce-related costs, costs that are variable with the incremental volumes gathered, processed and transported on our systems, the acquisition of gathering and processing assets in north Texas and repair and maintenance and related costs resulting from maintenance and downtime at three of our processing facilities.

Marketing

Our Marketing segment incurred losses of $42.4 million in 2005, which include unrealized, non-cash mark-to-market losses of $50.3 million, compared with $3.6 million of operating income for the corresponding period in 2004. The operating income of our Marketing segment in 2005 was affected by the following factors:

- Strong growth in natural gas production in the Texas markets we serve has created constraints in the available pipeline capacity used by our Marketing business to transport and deliver natural gas into premium-priced downstream markets. These pipeline constraints have limited the ability of our Marketing business to sell natural gas into these more attractive markets until additional pipeline capacity can be acquired and other alternatives become available.

- During the last four months of 2005, supply disruptions in the Gulf of Mexico region caused by hurricanes Katrina and Rita created greater demand for natural gas from the onshore production areas that our Marketing business serves, increasing our ability to optimize revenue from the sale of unhedged natural gas volumes to areas of greater demand.

- We were adversely affected by significant non-cash volatility associated with our portfolio of derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133.

Derivative Transactions and Hedging Activities

We record all financial instruments in the consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133. For those derivative financial instruments that do not qualify for hedge accounting, all changes in fair market value are recorded through our Consolidated Statements of Income each period. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, although that is not our intent.

A volatile natural gas and NGL pricing environment during our fiscal year ended December 31, 2005, produced non-cash mark-to-market losses of $58.4 million and negatively affected our operating results. While these mark-to-market losses create volatility in our results, the derivative financial instruments do not affect our cash flow until they are settled. We expect these non-cash losses to reverse in future periods as we settle the derivative financial instruments against the underlying physical transactions. Because of the economic benefit we receive by minimizing the volatility in our cash flows by using derivative financial instruments to hedge our portfolio of natural gas and NGL, we intend to continue using them. Our

continued use of derivative financial instruments may result in additional unrealized, non-cash losses or gains in the future.

The following table presents the unrealized losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value losses	**December 31, 2005**	**December 31, 2004**	**December 31, 2003**
	(in millions)		
Natural Gas segment			
Ineffectiveness	$ 2.5	$ 1.1	$
Non-qualified hedges	5.6		
Marketing			
Non-qualified hedges	41.3	2.1	0.3
Discontinuance	9.0		
Derivative fair value losses	$ 58.4	$ 3.2	$ 0.3

In connection with the sale of a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on forecasted sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that were qualified for and designated as cash flow hedges of forecasted sales of 273 Bpd of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bpd of NGLs for the same term.

RESULTS OF OPERATIONS BY SEGMENT

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota, and Mid-Continent systems. We provide a detailed description of each of these systems in Item 1. Business. The following tables set forth the operating results and statistics of our Liquids segment for the periods presented:

	Year Ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Operating Results			
Operating revenues	$ 418.0	$ 409.3	$ 344.2
Operating and administrative	(144.2)	(128.9)	(104.1)
Power	(74.8)	(72.8)	(56.1)
Depreciation and amortization	(71.7)	(68.5)	(59.5)
Operating expenses	(290.7)	(270.2)	(219.7)
Operating Income	$ 127.3	$ 139.1	$ 124.5
Operating Statistics			
Lakehead system:			
United States(1)	1,036	1,064	1,003
Province of Ontario(1)	303	358	351
Total deliveries(1)	1,339	1,422	1,354
Barrel miles (billions)	363	367	345
Average haul (miles)	692	706	698
Mid-Continent system deliveries(1)(2)	236	237	
North Dakota system deliveries(1)	87	85	77

(1) Average barrels per day in thousands.

(2) Ten months of deliveries in 2004.

Year ended December 31, 2005 compared with year ended December 31, 2004

Our Liquids segment accounted for $127.3 million of operating income in 2005, representing a decrease of $11.8 million or 8% over the same period in 2004. Lower results on the Lakehead system were modestly offset by stronger results on our North Dakota system and a full twelve-month contribution from our Mid-Continent system compared with a ten-month contribution for the same period in 2004.

Operating revenue in 2005 increased by $8.7 million or 2% to $418.0 million, compared with $409.3 million for the same period in 2004. Our Mid-Continent assets contributed higher operating revenue of approximately $6.6 million for the additional two months of ownership in 2005 compared to 2004. Overall tariff increases and longer hauls on our North Dakota system were mostly offset by lower deliveries on the Lakehead system during 2005.

Average daily crude oil deliveries on the Lakehead system decreased approximately 6%, from 1.422 million Bpd during 2004 to 1.339 million Bpd during 2005. This resulted in lower operating revenue for 2005 of approximately $20.0 million. The decrease is the result of lower than expected crude oil supply in western Canada from three factors. First, Suncor, an oil sands producer in Alberta, Canada, had a fire at their upgrader site on January 4, 2005. As a result of the incident, Suncor s production was reduced by an average of 89,000 Bpd during the first nine months of 2005. In late September, Suncor announced that repairs to the upgrader site and an expansion were completed and production capacity has increased as a result. Second, western Canadian crude oil supply available for delivery on our Lakehead system was also reduced during 2005 due to lower bitumen supplies. The nature of the cyclic steaming process used to extract bitumen from the ground can cause production timing differences during the year. Finally, during the second quarter of 2005, Kinder Morgan, Inc., an unrelated company, completed an expansion on its Express Pipeline system. The expansion increased capacity on this pipeline by approximately 108,000 Bpd. Given the volume commitments on the Express Pipeline expansion, coupled with the lower western Canadian crude oil supply as noted above, deliveries on our Lakehead system were negatively impacted for 2005. Management believes that holders of firm capacity on the Express Pipeline will first satisfy their commitments to that pipeline before moving incremental barrels on the Lakehead system.

Increases in average tariffs on all three Liquids systems resulted in higher operating revenue by approximately $17.6 million. These tariff increases were mostly the result of the annual index rate increase of approximately 3.63% allowed by the FERC that became effective July 1, 2005, on our base system tariffs. On the Lakehead system, new tariffs also went into effect on April 1, 2005 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system. Longer hauls on our North Dakota system also contributed to higher average tariffs, as production in Montana continued to be strong during 2005.

Operating and administrative expenses for 2005 increased by $15.3 million to $144.2 million, compared with $128.9 million in 2004. The increase was attributable to the following factors:

(1) workforce related costs increased by approximately $6.9 million due to higher pension, medical and other benefits costs, along with increased administrative, regulatory and compliance support;

(2) operating and administrative expenses on our Mid-Continent system increased approximately $2.9 million due to a full year s ownership in 2005, compared with ten months in 2004;

(3) capital project recoveries were lower by approximately $2.8 million due to a decrease in utilization of our workforce on capital projects and a reduction in construction activity on our Liquids systems;

(4) oil measurement losses increased approximately $2.4 million.

Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;

- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and

- revaluation losses, which are a function of crude oil prices, the level of the carrier s inventory and the inventory positions of customers.

During 2005, the increase in oil measurement losses was a function of two factors:

1. Higher volumetric physical losses associated with changes in commodity properties and measurement, coupled with higher oil prices that made the monetary value of normal physical losses more expensive. During 2005, the average West Texas Intermediate crude oil price was approximately $56 per barrel compared with approximately $41 per barrel during 2004;

2. Wider light/heavy crude price differentials made degradation losses more expensive. During 2005, light/heavy differentials were approximately $21 per barrel compared with approximately $14 per barrel in 2004.

Power costs increased $2.0 million, or 3%, in 2005 compared with 2004, mostly due to higher electricity rates and a full twelve-month contribution from our Mid-Continent system compared to ten-months in 2004, partially offset by lower energy consumption related to lower Lakehead volumes. Power costs associated with the Mid-Continent system increased approximately $1.5 million in 2005.

Depreciation and amortization increased $3.2 million, or 5%, in 2005 compared to 2004. The increase is driven primarily by a full twelve-month contribution from our Mid-Continent system and an increase in the depreciable asset base on our Lakehead system in 2005.

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Liquids segment accounted for $139.1 million of operating income, an increase of $14.6 million or 12% over 2003 Liquids operating income. The primary driver of the increase in 2004 was our newly acquired Mid-Continent system, which contributed $13.7 million of operating income to the Liquids segment.

Segment operating revenues increased by $65.1 million or 19% in 2004 compared with 2003, largely due to a $36.7 million contribution from our Mid-Continent system. Operating revenues from our Lakehead system increased $22.9 or 7%, mostly due to increased deliveries. Deliveries on our Lakehead system increased 5% during 2004, primarily from increased production of western Canadian crude oil transported on that system. Overall, production of western Canadian crude oil increased in the last two years mainly due to the start up of new oil sands projects in the province of Alberta. These latest oil sands projects differ from conventional oil production in two ways. First, oil sands deposits are a mixture of bitumen, water, sand and clay. As a result, oil production takes the form of either mining the oil sands from subsurface deposits and separating out the water, sand and clay components, or, if the deposits are deeper, heating the reservoir sufficiently to flow the pure bitumen to the well base and then to the surface. Second, the bitumen requires either upgrading or blending prior to being sent to market. The upgrading process partially refines the bitumen into a crude stream, which can be readily refined by most conventional refineries. This product is known as synthetic crude oil. During 2004, crude oil production increased in western Canada, primarily due to the start up of the Athabasca Oil Sands Project in June 2003. The AOSP is owned by Shell Canada Limited, Chevron Canada Limited and Western Oil Sands L.P., and consists of oil sands mining and bitumen extraction operations with a current capacity of

155,000 Bpd. 2004 deliveries on our Lakehead system reflect a full year s impact from this new source of supply. Operating revenues on our North Dakota system also increased in 2004 by $5.5 million or 37%, primarily due to an increase in transportation of longer-haul, higher margin barrels resulting from improved production in Montana.

Operating and administrative expenses of our Liquids segment increased by $24.8 million, or 24%, in 2004 compared with 2003, mostly due to our new Mid-Continent system, which had operating and administrative expenses of $13.4 million. Operating and administrative expenses on our Lakehead system increased by $10.7 million, or 11%. This increase was attributable primarily to three factors:

(1) Workforce related costs increased by $7.6 million due to higher pension and medical costs and other related general and administrative expenses.

(2) Oil measurement losses increased by $7.6 million due to the impact of higher crude oil prices and increased volumes on the system, which contributed to the physical losses. We made refinements in the oil measurement loss estimation process in valuing different types of crude oil on station lines resulting in an increase of approximately $3.4 million to our oil measurement loss. The refinements were the result of engineering studies completed in the fourth quarter of 2004.

(3) Property taxes increased $2.6 million, or 15%. We have experienced a trend of increasing property taxes partially due to new facilities placed into service, and also due to increases from the taxing authorities in counties and states where our pipeline assets are located.

These increases in operating and administrative expenses on our Lakehead system were partially offset by lower leak remediation and repair costs of approximately $6.1 million, or 90%.

Power costs increased $16.7 million, or 30%, in 2004 compared with 2003, mostly due to the growth in volumes on the Lakehead system and higher generating rates attributable to higher demand and fuel costs. Power costs associated with the Mid-Continent system were $5.2 million in 2004.

Depreciation and amortization increased $9.0 million, or 15%, over 2003. Depreciation on the Mid-Continent system accounted for $4.4 million and the balance relates to new facilities placed into service within our Liquids segment during 2003 and 2004.

Future Prospects for Liquids

Historically, Western Canada has been a key source of oil supply serving U.S. energy needs. Canada s oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. New production from the oil sands is expected to grow progressively during the next five years, with an additional 890,000 to 930,000 Bpd available by 2010. Conventional oil production is expected to decline by about 130,000 Bpd during the same period. The net increased production will result from an estimated $55 billion of active or planned projects that are being developed in the oil sands.

Enbridge and the Partnership are actively working with our customers to develop transportation options that will allow Canadian crude oil access to new markets. After receiving strong shipper support during an Open Season, the Partnership and Enbridge announced approval of the 400,000 Bpd Southern Access expansion project, which has received endorsement from CAPP. A decision from the FERC on tariff principles negotiated with shippers is expected before mid-year 2006. Fieldwork has commenced to ensure completion in early 2009, with capacity increases to start in 2007.

The U.S. portion of the expansion will be undertaken on our Lakehead System with the first stage to add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd by early 2008. The first stage includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in early 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system. The design will also permit a further 400,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior, when required by shippers.

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Cushing, Oklahoma to Chicago, and has reversed its flow. The pipeline has been renamed the Spearhead Pipeline and will provide capacity to deliver 125,000 Bpd into the major oil hub at Cushing in early 2006. We expect to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

The Partnership and Enbridge believe that the Southern Access Program, the Spearhead pipeline reversal, and other initiatives to provide access to new markets in the Midwest, Mid-continent and Gulf Coast, offer flexible solutions to future transportation requirements of western Canadian crude oil producers, and the in-service timing of these solutions is in line with prospective shipper needs.

Average daily crude oil deliveries on the Lakehead system are expected to increase by approximately 240,000 Bpd during 2006, from 1.34 million Bpd in 2005 to approximately 1.58 million Bpd in 2006. The increase is mainly attributable to the re-start of Suncor s upgrader in late September 2005 after the January 2005 fire, along with commissioning of Suncor s expansion in the last quarter of 2005. In addition to these volumes, we expect the commissioning of Syncrude s UE-1 expansion in mid-2006, resulting in ultimate incremental production of 100,000 Bpd.

Our North Dakota system has benefitted over the past two years from the six and 28 percent average annual production growth in North Dakota and Montana, respectively. We expect deliveries on our North Dakota system to be approximately 92,000 Bpd in 2006.

Our Mid-Continent system consists of the Ozark and the West Tulsa pipelines. The West Tulsa pipeline moves crude oil from Cushing to Tulsa. Throughput deliveries on this system are expected to continue to remain stable, given the recent strength in refinery margins experienced by the industry. The Ozark pipeline system transports crude oil from Cushing to Wood River and provides access to the Wood River, east of Patoka, and Minnesota refining areas through its connection to other systems. The Ozark system depends upon the demand of the Wood River and east of Patoka refineries for crude oil from west Texas, and imports from the Gulf Coast. We expect steady to declining throughputs as more growth in Canadian crude oil displaces imports from the Gulf Coast and demand for domestic west Texas crude oil. We expect deliveries on our two Mid-Continent pipelines to be approximately 210,000 Bpd in 2006.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, as well as treating and processing plants and related facilities. Collectively, these systems include:

- approximately 11,000 miles of natural gas gathering and transmission pipelines including four FERC-regulated transmission pipeline systems;
- eight natural gas treating plants;
- fifteen natural gas processing plants; and
- trucks, trailers and railcars used for transporting NGLs, crude oil and carbon dioxide.

The following tables set forth the operating results of our Natural Gas segment assets and average daily volumes of our major systems in MMBtu/d for the periods presented:

	Year Ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Operating revenues	$ 2,352.1	$ 1,319.9	$ 958.5
Cost of natural gas	(2,018.7)	(1,031.8)	(754.9)
Operating and administrative	(175.0)	(138.3)	(102.3)
Depreciation and amortization	(66.0)	(51.7)	(37.7)
Gain on sale of assets	18.1		
Expenses	(2,241.6)	(1,221.8)	$ (894.9)
Operating income	$ 110.5	$ 98.1	$ 63.6

	Year Ended December 31,		
	2005	**2004**	**2003**
Average Daily Volume (MMBtu/d)			
East Texas	860,000	676,000	579,000
Anadarko(1)	488,000	357,000	256,000
North Texas	265,000	192,000	
South Texas(2)	33,000	40,000	38,000
UTOS	158,000	219,000	213,000
Midla	106,000	103,000	108,000
AlaTenn	59,000	62,000	61,000
KPC	31,000	48,000	53,000
Bamagas	29,000	25,000	14,000
Other Major Intrastates(1)	186,000	176,000	182,000
Total	2,215,000	1,898,000	1,504,000

(1) Anadarko includes the combined systems previously referred to separately as Anadarko and Palo Duro. The Palo Duro volumes were formerly included with Other major intrastates.

(2) We sold the South Texas assets in December 2005.

We recognize revenue upon delivery of natural gas and NGLs to customers, and/or when services are rendered, pricing is determinable and collectibility is reasonably assured. We derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based Arrangements: Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services provided and do not depend directly on commodity prices. Revenues of the Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of our FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes.

Other Arrangements: We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Please refer to Item 7A. Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk and Note 15 of our Consolidated Financial Statements beginning on page F-1 of this report for more information about our derivative activities.

These other types of arrangements are categorized as follows:

- Percentage-of-Index-Contracts Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Percentage-of-Proceeds Contracts Under the terms of these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.

- Percentage-of-Liquids Contracts Under these contracts, we receive a negotiated percentage of NGLs and condensate from natural gas that requires processing. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs and condensate.

- Keep-Whole Contracts Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account the residue gas resulting from processing at market prices. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with a British thermal unit content equivalent to the original raw gas we received.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our unitholders from volatility in our cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

Year ended December 31, 2005 compared with year ended December 31, 2004

Our Natural Gas segment contributed $110.5 million of operating income in 2005, representing an increase of $12.4 million, from the $98.1 million earned in 2004. Continuing favorable natural gas and NGL prices contributed to average daily volume increases of 17 percent in 2005 on our major natural gas systems compared with 2004. The increase in volumes is primarily the result of additional wellhead supply contracts on our East Texas and Anadarko systems, as well as the additional volumes on the North Texas system associated with the gathering and processing assets we acquired in January 2005. Drilling activity continues to increase in the Anadarko Basin, Bossier Trend and Barnett Shale areas as evidenced by increasing rig counts and production volumes over the past several years. Additionally, completion of the East Texas expansion project in late June 2005 contributed modestly to the growth in volumes for the year 2005. With continued investment in our systems to expand capacity, we expect our major natural gas systems to benefit from the increase in production volumes expected to result from the continuing increase in drilling activities in the basins we serve.

Partially offsetting the positive operating results derived from the increases in gathering, processing and transportation volumes on our natural gas systems were non-cash, mark-to-market net losses of $8.1 million associated with our derivative transactions and hedging activities. Included in Cost of natural gas are non-cash losses of $2.5 million resulting from ineffectiveness associated with our qualified cash flow hedges and $5.6 million of non-cash mark-to-market losses from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The non-cash losses primarily result from the significant increases in forward natural gas and NGL prices during the year. The increase in prices reduces the fair market value of these derivative financial instruments because the fixed price component of these derivatives is significantly less than the market price of natural gas at each of the forward settlement points.

Also included in our operating results for the year ended December 31, 2005 is a gain of $18.1 million we realized in December 2005, when we divested non-strategic assets located within our East and South Texas systems. We sold for $105.4 million in cash, a processing plant and related facilities, and other gathering and processing assets with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million. In connection with this sale, we paid approximately $16.3 million to settle natural gas hedges associated with the natural gas produced by these assets. We had previously recorded unrealized losses associated with the natural gas hedges that were realized upon settlement. The reported amounts are subject to change pending the final settlement of the sale.

A variable element of the Natural Gas segment s operating income is derived from keep-whole processing of natural gas primarily on our Anadarko and East Texas systems. This contract structure requires us to process natural gas at times when it may not be economical to do so. This can happen when natural gas prices are unusually high or NGL prices are unusually low. During 2005, although natural gas prices were unusually high, they were more than offset by favorable NGL prices. Operating revenue less cost of natural gas derived from keep-whole processing for the year 2005 was approximately $29.0 million compared with $17.2 million in 2004.

Operating and administrative costs of our Natural Gas segment were $175.0 million, or 27% greater for 2005 than 2004, primarily as a result of increased workforce related costs and costs that are variable with volumes. Workforce related costs increased $11.8 million due to higher pension, medical and other benefits, as well as additional administrative, regulatory and compliance support. Costs that are incremental with volumes, such as chemicals, materials and supplies and direct workforce expenses increased by $10.5 million. Additionally, the natural gas gathering and processing assets we acquired in January 2005 contributed to the cost increases of approximately $7.2 million. As well, our maintenance costs increased by approximately $4.9 million in 2005 due to several processing plants that underwent major repairs, one of which was included with the recently divested assets.

Our depreciation and amortization expense for the year 2005 exceeded the amount reported for 2004 by approximately $14.3 million, primarily as a result of acquisitions and significant capital projects completed and placed in-service during 2005. The increase in depreciation expense was partially offset by modest extensions of the depreciable lives of our major pipeline systems as a result of a depreciation study completed during the third quarter of 2005. Based on a third-party study commissioned by management, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented

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effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. Depreciation expense for the year ended December 31, 2005 was approximately $2.5 million lower as a result of the new depreciation rates.

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Natural Gas segment accounted for $98.1 million of operating income, an increase of $34.5 million, or 54%, over 2003 Natural Gas operating income.

Compared with 2003, average daily volumes on our major Natural Gas systems increased 26% in 2004, mostly due to the contribution of our North Texas system from the acquisition date of December 31, 2003. Our North Texas system contributed $22.9 million to operating income in 2004, which was consistent with our expectations for the first year of ownership. Volumes on our East Texas system increased by 17% in 2004, compared with the same period in 2003, as a result of increased drilling by producers of gas wells in the areas served by the system. These volume increases resulted in higher operating revenue less cost of natural gas of $7.9 million compared with 2003. Volumes on our Anadarko system increased by approximately 32% in 2004, compared with the same period in 2003. The growth is a result of increased drilling activity in the Texas panhandle and western Oklahoma regions. The higher volumes contributed to an increase of $11.0 million in operating revenue less cost of natural gas.

High natural gas prices positively impacted volumes on our gathering and processing systems. This positive impact was compounded by favorable processing economics in 2004. As described in our 2005 comparison, keep-whole processing is a variable element of the Natural Gas segment s operating income. During 2004, operating income associated with keep-whole processing was approximately $17.2 million compared with $1.9 million in 2003. During 2004, natural gas prices were high but were more than offset by favorable NGL prices.

On our East Texas system, we processed 191,420 MMtbu/d of natural gas in 2004, which was an increase of 28% compared with volumes processed in 2003. Due to more favorable NGL pricing conditions in 2004, processing activities contributed $10.0 million of operating income. This compares with $1.7 million of operating income for processing activities in 2003. The increase in business activity on our East Texas system has resulted in higher operating revenue and administrative expenses of $7.8 million, or 17%, in 2004 compared with 2003. These costs are mostly variable in nature and relate to higher workforce related costs associated with an increase in our operations staff, as well as higher overall benefit costs and an increase in repairs and maintenance expenses. As a result, operating income on our East Texas system increased $2.9 million, or 10%, in 2004 compared with 2003.

Similar to our East Texas system, processing results improved on our Anadarko system during 2004 due to a more favorable natural gas and NGL pricing environment. On our Anadarko system, we processed 111,007 MMBtu/d of natural gas in 2004, which was an increase of 35% compared with volumes processed in 2003. Processing activities contributed to $7.2 million of operating income in 2004. This compares with $0.2 million of operating income for processing activities in 2003. These improvements to operating income were partially offset by higher operating and administrative expenses mostly related to variable costs associated with the increased volumes on the system. As a result, operating income on the Anadarko system increased by $16.0 million, or 175%, in 2004 compared with 2003.

The increase in business activity on our Natural Gas systems has resulted in higher operating and administrative expenses of $36.0 million in 2004 compared with 2003. These costs are mostly variable in nature and relate to higher workforce related costs associated with an increase in our operations staff, as well as higher overall benefit costs and an increase in repairs and maintenance expenses in relation to the higher volumes.

The remainder of the change in operating income in the Natural Gas segment was due to overall decreased results on the balance of our natural gas systems.

Future Prospects for Natural Gas

Our natural gas assets are located in the Gulf Coast and Mid-continent regions of the United States, two of the premier natural gas producing areas. As a result, there are many opportunities to connect new natural gas supplies either by installing new facilities or acquiring adjacent third-party gathering operations. Consolidation with neighboring facilities will extract efficiencies by eliminating costs, for example, by combining redundant facilities, increasing volume, and increasing processing margins. These opportunities tend to involve modest amounts of capital with attractive rates of return.

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. The market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. Although one of our objectives is to grow our natural gas business through acquisitions, we may and have pursued opportunities to divest of any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During 2005, increased drilling in the areas where our gathering systems are located has generally contributed to our volume growth. We expect the growth trend in these areas to continue in the future as evidenced by third-party reserve studies and the increase in rig counts in the areas served by our systems. Continuing advances in seismic and drilling completion technology, along with robust energy prices, have been key drivers for the higher drilling activity levels in such areas as the tight gas and gas shale locations of the Mid-Continent and East Texas. Other advances in drilling technology are enabling producers to more economically extract natural gas from wells and increase well productivity.

One of the prominent areas in which this is occurring is the Barnett Shale play in North Texas. The Barnett Shale is a prominent natural gas formation within the Fort Worth Basin, and it is being actively developed. The formation produced approximately 110 MMcf/d in 1999 and had grown to over 1,200 MMcf/d by July 2005. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of Barnett Shale development.

The rate of growth on our Anadarko system continues to exceed projections as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties. To accommodate this continuing volume growth, the Anadarko system requires additional processing capacity and field compression. We are set to expand our system processing capacity in the region from 230MMcf/d to approximately 400MMcf/d, which we expect to place in service in early 2007.

In the East Texas region, our overall system receipts rose to over 800 MMbtu/d shortly after we brought our newly constructed 500 MMcf/d intrastate transmission pipeline on line in mid-2005 to carry increased volumes of natural gas to the Carthage hub. Producer drilling plans in regional plays, including the Bossier trend and Deep Bossier, are expected to result in continued production growth. To accommodate this further growth, we will increase our gathering and treating infrastructure and market access capability. To further this objective we have committed to a $530 million expansion of our East Texas system. The key components of this project include:

- A 36-inch diameter intrastate pipeline from Bethel, Texas to Orange County, Texas with capacity of approximately 700 MMcf/d, will be completed in stages throughout 2007. The new line will provide service to a number of major industrial and power companies in Southeast Texas and will cross a number of interstate pipelines.

- A 200 MMcf/d treating facility to be built near Marquez, Texas will be connected to the 36-inch pipe via a new 24-inch diameter pipeline, to be completed in early 2007.

- A number of upstream facilities, including gathering pipelines to tie existing facilities into the new intrastate pipeline, will also be completed in early 2007.

When fully operational in late 2007, the new assets will be an additional source of stable cash flow for us. We are also evaluating other projects that further integrate all our major Texas-centered pipeline systems.

We are also working with Enbridge on its proposed interstate extension from our Texas natural gas midstream business. Enbridge announced an Open Season on a proposed 330 mile, 1 billion cubic feet per day pipeline from Texas through Louisiana, to interconnect with other interstate systems in Western Mississippi. This project, if supported by shippers, could draw, additional volumes through our East Texas system and its proposed expansion announced in January 2006.

Our Bamagas system has agreements to provide transportation of up to 276,000 MMbtu/d of natural gas for a remaining period of 17 years to two utility plants that are indirectly owned by Calpine Corporation (Calpine). Calpine is the sole customer served by the Bamagas system. The Bamagas system receives a fixed demand charge of $0.07 per MMBtu of natural gas for 200,000 MMBtu/d, regardless of whether the capacity is used. In December 2005, Calpine and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas sytem, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. In connection with the bankruptcy filing, Calpine has announced receipt of commitments for up to $2 billion of Debtor in Possession, or DIP financing to allow for the continued operation of their power plants. Our Bamagas system is the sole supplier of natural gas to these two utility plants, and we expect the subsidiary that owns these utility plants to continue performing under the terms of our agreement. Due to the recent nature of the bankruptcy filing, we are unable to determine the extent of any losses to which we may be subject as a result of the bankruptcy. We are actively monitoring the Calpine bankruptcy proceedings and will recognize any losses that may result when it becomes evident that a loss has been incurred.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented:

	Year Ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Operating revenues	$ 3,706.8	$ 2,562.5	$ 1,869.6
Cost of natural gas	(3,744.6)	(2,555.3)	(1,857.8)
Operating and administrative	(4.1)	(3.4)	(2.2)
Depreciation and amortization	(0.5)	(0.2)	(0.2)
Expenses	(3,749.2)	(2,558.9)	(1,860.2)
Operating income (loss)	$ (42.4)	$ 3.6	$ 9.4

Natural gas purchased and sold by our Marketing segment is priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At their request, we will enter into long-term fixed price purchase or sales contracts with our customers and generally will enter into offsetting hedged positions under the same or similar terms.

Marketing pays third-party storage facilities and pipelines for the right to store and transport natural gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities.

As a result of the widespread damage caused by hurricanes Katrina and Rita, the major credit rating agencies have issued negative credit implications for several of our industrial and utility customers. Although we do not anticipate any significant deterioration in the credit standing of our other customers, we continue to monitor their financial condition, and expect improvement in their credit standing as system outages are restored and property damage repaired.

Year ended December 31, 2005 compared with year ended December 31, 2004

A majority of the operating income of our Marketing segment is derived from selling natural gas received from customers on our Natural Gas segment pipeline assets to end users of natural gas. A majority of the natural gas is purchased in Texas markets where we have limited physical access to the primary interstate pipeline delivery points, or hubs such as Waha, Texas and the Houston Ship Channel. As a result, our Marketing business must use third-party pipelines to transport the natural gas to these markets where it can be sold to customers. However, physical pipeline constraints often require our Marketing business to transport natural gas to alternate market points. Under these circumstances, our Marketing segment will sell the purchased gas at a pricing index that is different from the pricing index at which the gas was purchased. This creates a price exposure that arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the spread. The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create another element of volatility in the operating results of our Marketing segment.

To ensure that we have access to primary pipeline delivery points, we often enter into firm transportation agreements on interstate and intrastate pipelines. In order to offset the demand charges associated with these firm transportation contracts, we look for market conditions that allow us to lock in the price differential or spread between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed return, inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating the demand charges on firm transportation agreements and limiting our exposure to cash flow volatility that could arise in markets where the firm transportation becomes uneconomic. However, the structure of these transactions precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas basis swaps, we contract for storage to assist balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawn natural gas, as well as storage fees, the injection and withdrawal price differential, or spread is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although each of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact the income statement.

During the third and fourth quarters, disruptions of natural gas supplies from facilities in the Gulf of Mexico region caused by hurricanes Katrina and Rita created greater demand for natural gas production from our onshore Natural Gas segment pipeline assets, increasing our ability to optimize natural gas supply to areas of strongest demand. As a result of the hurricanes, unusual volatility in the prices of natural gas created greater spreads on our natural gas volumes.

Although our Marketing segment was not adversely affected from the temporary supply disruptions in the Gulf of Mexico, we generally continue to be affected by lower unit margins on natural gas volumes purchased due to physical pipeline constraints. The recent completion of our East Texas system expansion has partially alleviated these constraints; however, increasing production volumes will continue to create additional market outlet constraints. These additional pipeline constraints will require continued use of third-party pipelines in East Texas. This situation is not limited to the East Texas region. Pricing in our natural gas supply markets is expected to continue to experience increasing pressure due to a greater supply of natural gas from the Rocky Mountains, Mid-Continent and North Texas. For this reason we continue to increase our commitments on third-party pipelines to mitigate these constraints and provide more attractive market outlets for our natural gas supply. However, there continues to be timing differences between the acquisition of new third-party pipeline capacity and the negotiation of applicable downstream sales agreements. Until new markets are developed, our Marketing segment sells greater portions of its natural gas supply in less attractive short-term markets.

For the year ended December 31, 2005, our Marketing segment incurred losses of $42.4 million, which include non-cash mark-to-market losses of $48.2 million, compared with earning $3.6 million of operating income for the corresponding period in 2004. The non-cash, mark-to-market losses are associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. During 2005, we revised our business strategy for the use of derivative financial instruments associated with the transportation and storage of natural gas to afford us the ability to respond to changing economic conditions. The flexibility provided by our revised strategy precludes us from continuing the use of hedge accounting with regard to these transactions. Under SFAS No. 133, if the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation, the financial instruments must be marked-to-market each period with the change in fair market value recorded in earnings. However, SFAS No. 133 does not allow us to mark-to-market the change in value of the related underlying physical transaction, and this difference creates earnings volatility when the spreads move. We expect these net mark-to-market losses to be predominantly offset when the related physical transactions are settled (refer also to the discussion included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 15 of our Consolidated Financial Statements beginning on page F-1 of this report).

Year ended December 31, 2004 compared with year ended December 31, 2003

Our Marketing segment accounted for $3.6 million of operating income, a decrease of $5.8 million compared with $9.4 million contributed in 2003. Operating income in 2004 for our Marketing segment included a loss of $2.1 million associated with financial natural gas basis swap transactions that do not qualify for hedge accounting treatment under SFAS No. 133. The unqualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value will continue to impact the income statement until the derivative financial instruments are settled. In 2003, the loss associated with unqualified derivatives was $0.3 million.

Our Marketing segment was also impacted by lower unit margins on natural gas volumes purchased due to physical pipeline constraints. Performance of the Marketing segment was also negatively impacted by demand charges on new third-party pipeline capacity that is utilized to transport natural gas from markets that are over supplied with natural gas in our Natural Gas segment to new markets. Pricing in our natural gas supply markets is expected to come under increasing pressure due to higher natural gas supplies from the Rocky Mountains and North Texas. For this reason we have increased our commitments on third-party pipelines to provide more attractive market outlets for our natural gas supply.

Corporate

Year ended December 31, 2005 compared with year ended December 31, 2004

Interest expense was $107.7 million in 2005 compared with $88.4 million in 2004. The increases are the result of higher debt balances and higher weighted average interest rates of approximately 5.78% for the year ended December 31, 2005, compared with approximately 5.56% during 2004. The increase in our debt balances at December 31, 2005 is due to the gathering and processing assets in North Texas we acquired in January 2005, in addition to the capital expenditures we have made to expand our existing systems to improve the service capabilities of our assets.

Year ended December 31, 2004 compared with year ended December 31, 2003

Interest expense was $88.4 million in 2004 compared with $85.0 million in 2003. The $3.4 million increase in 2004 compared with 2003 reflects higher average borrowings, partially offset by a decrease in our average borrowing rates.

Included in our results for the year ended December 31, 2004 was a charge related to rate refunds payable on KPC for $13.6 million associated with rates charged to customers of KPC prior to our ownership. We extinguished this obligation in the first quarter of 2005 and have not incurred any similar rate refunds during the year ended December 31, 2005.

LIQUIDITY AND CAPITAL RESOURCES

General

We believe that our ability to generate cash flow, in addition to our access to capital is sufficient to meet the demands of our current and future operating growth and investment needs. Our primary cash requirements consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to our partners and acquisitions of new assets and businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures, debt service payments and quarterly distributions to our partners, are expected to be funded by operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under the commercial paper program we established in April 2005, our Credit Facility, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

During 2005, we shifted our business strategy to an emphasis on developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. The internal growth projects we have planned for our Natural Gas business (see Natural Gas segment Future Prospects), coupled with the Southern Access Program on our Lakehead system (see Liquids segment Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a balanced combination of additional issuances of partnership capital and long-term debt. Our planned internal growth projects will require us to bear the cost of constructing these new assets before we will begin to realize a return on them. While these major projects are under construction, our ability to increase distributions, while funding these projects is likely to be limited.

Capital Resources

Equity Capital

Our ability to execute our growth strategy and complete our planned construction projects is dependent upon our access to the capital necessary to fund these projects. During 2005, we raised net proceeds of approximately $268.6 million from public offerings of our common units, including $5.7 million from our General Partner to maintain its 2-percent general partner interest. We primarily used the proceeds from these offerings to temporarily reduce amounts outstanding under our Credit Facility and our commercial paper program which were initially used to finance our capital expansion projects and acquisitions. The following table presents historical information about our public equity offerings since January 2003:

Issuance Date	**Number of Class A Common units Issued**	**Offering Price per Class A Common unit**	**Net Proceeds to Partnership**(1)	**General Partner Contribution**(2)	**Net Proceeds Including General Partner Contribution**
	($in millions, except per unit amounts)				
2005:					
December 2005	136,200	$ 46.000	$ 6.0	$ 0.2	$ 6.2
November 2005	3,000,000	$ 46.000	132.1	2.8	134.9
February 2005	2,506,500	$ 49.875	124.8	2.7	127.5
2005 Totals	5,642,700		$ 262.9	$ 5.7	$ 268.6
2004:					
September 2004	3,680,000	$ 47.900	$ 168.6	$ 3.6	$ 172.2
January 2004	450,000	$ 50.300	21.6	0.4	22.0
2004 Totals	4,130,000		$ 190.2	$ 4.0	$ 194.2
2003:					
December 2003	5,000,000	$ 50.300	$ 240.4	$ 5.0	$ 245.4
May 2003	3,850,000	$ 44.790	165.5	3.5	169.0
2003 Totals	8,850,000		$ 405.9	$ 8.5	$ 414.4

(1) Net of underwriters fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Available Credit

A significant source of our liquidity is provided by the commercial paper market. In April 2005, we established a $600 million commercial paper program that is supported by our long-term Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $200 million. At December 31, 2005, we had $330.0 million in principal amount of commercial paper outstanding and could issue $270.0 million in principal amount of commercial paper.

Our Credit Facility also provides us with another significant source of liquidity. We amended our Credit Facility twice during 2005, to among other things, extend the maturity to April 2010; increase the letter of credit sub limit to $300 million; increase the available commitments to $800 million with the right to request, subject to approval by the Board of Directors of Enbridge Management, an increase in commitments available up to an aggregate principal amount of $1 billion; decrease the Applicable Rate as set forth in the Credit facility; and extend to December 2006, the requirement to maintain a Consolidated Leverage Ratio, as defined in the Credit Facility, of not more than 5.25:1. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2005, no amounts had been borrowed against our Credit Facility and we had approximately $149.3 million of letters of credit outstanding. We could borrow $320.7 million under the terms of our Credit Facility.

Indebtedness and Other Payment Obligations

Our Credit Facility and debt consist of the following:

	December 31,			
	2005		**2004**	
	(in millions)			
Current portion of First Mortgage Notes	$	31.0	$	31.0
Long-term debt:				
Commercial Paper	$	329.3	$	
Credit Facility			175.0	
First Mortgage Notes	155.0		186.0	
4.00% senior notes due 2009 or notes due 2009	200.0		200.0	
7.90% senior notes due 2012	100.0		100.0	
4.75% senior notes due 2013	200.0		200.0	
5.35% senior notes due 2014	200.0		200.0	
7.00% senior notes due 2018	100.0		100.0	
7.125% senior notes due 2028	100.0		100.0	
5.95% senior notes due 2033	200.0		200.0	
6.30% senior notes due 2034	100.0		100.0	
Unamortized discount	(1.4	)	(1.6	)
Total long-term debt	$	1,682.9	$	1,559.4
Loans from General Partner and affiliates	$	151.8	$	142.1

Commercial Paper Program

In April 2005, we established our $600 million commercial paper program that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. We repaid the entire amount previously outstanding under our Credit Facility with proceeds we obtained from issuing commercial paper under this program. Our Credit Facility remains undrawn and available to support our commercial paper program.

Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $200 million. At December 31, 2005, we had $330.0 million in principal amount of commercial paper outstanding, with unamortized discount of $0.7 million, at a weighted average interest rate of 4.36% and outstanding letters of credit totaling $149.3 million. At December 31, 2005, we could issue an additional $270 million in principal amount under our commercial paper program.

Credit Facility

Our Credit Facility, as amended, is a five-year term facility that matures in April 2010 with a current borrowing capacity of $800 million and a letter of credit sub limit of $300 million. Subject to the approval of Enbridge Management s Board of Directors, we have the right to request an increase in commitments

available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion. We pay interest on the amounts outstanding at variable rates equal to the Base Rate or a Eurodollar Rate as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the facility. We are also charged a facility fee on the entire amount of the Credit Facility, regardless of the amount drawn, which also varies depending on our credit rating.

Our Credit Facility contains restrictive covenants that require us to maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 5.25 times for twelve months through December 2006, at which time it decreases to 5.00 times, thereafter. At December 31, 2005, our interest coverage ratio was approximately 3.7 and our leverage ratio was approximately 4.2. Our Credit facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary.

At December 31, 2005, we had no balances outstanding under our Credit Facility and letters of credit totaling $149.3 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2005, we could borrow $320.7 million under the terms of our Credit Facility.

First Mortgage Notes

The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We were in compliance with these covenants at December 31, 2005. We believe these issuance tests will not negatively affect our ability to finance future expansion projects. Under the First Mortgage Note Agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If we repay the Notes prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by us.

Senior Notes

Our Senior Notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries. The borrowings under these Notes are non-recourse to our General Partner and Enbridge Management. These notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets to any Person, except in accordance with our indenture agreement. We were in compliance with these covenants at December 31, 2005.

We did not issue any Senior Notes during the year ended December 31, 2005. However, for the year ended December 31, 2004, we made the following senior note issuances:

- In December 2004, we issued $200.0 million in aggregate principal amount of our 5.35% Senior Notes due 2014 and $100.0 million in aggregate principal amount of our 6.30% Senior Notes due 2034 in a public offering, from which we received net proceeds of $297.1 million. We used the proceeds to repay a portion of our outstanding debt under bank Credit Facility.

- In January 2004, we issued $200.0 million in aggregate principal amount of our 4.0% Senior Notes due 2009 in a public offering, from which we received net proceeds of $198.3 million. We used the proceeds to repay a portion of our outstanding debt under bank Credit Facility.

All of our Senior Notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our Senior Notes are effectively junior in right of payment to any secured indebtedness that we may have and to all existing and future indebtedness and other liabilities of our subsidiaries, which own all of our operating assets. Additionally, all of our Senior Notes pay interest semi-annually and have varying maturities and terms as presented in the table above. Our Senior Notes do not contain any covenants restricting us from issuing additional indebtedness.

Loans from General Partner and affiliates

As of December 31, 2005 and 2004, we had $151.8 million and $142.1 million, respectively, in debt outstanding under a note to an affiliate of our general partner. This note relates to debt we assumed in connection with our acquisition of the Midcoast system in October 2002. The note matures in 2007 and has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The note is subordinate to our Credit Facility and other senior indebtedness. For the years ended December 31, 2005 and 2004, we converted interest payable related to this note in the amount of $9.7 million and $9.0 million, respectively, into long-term debt.

Credit Ratings

The following table reflects the ratings that have been assigned to our debt and the debt of our wholly-owned subsidiary, Enbridge Energy, Limited Partnership at December 31, 2005:

	Standard & Poor s	Moody s	Dominion Bond Rating Service
Enbridge Energy Partners, L.P.			
Corporate	BBB(stable)	NR	BBB
Commercial Paper	A-2	P-1	NR
Medium Term Notes & Unsecured Debentures	BBB	Baa2	BBB
Enbridge Energy, Limited Partnership			
Senior secured	BBB+	NR	NR
Senior unsecured	BBB	Baa1	NR

NR No rating is available

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2005:

	2006	2007	2008	2009	2010	Thereafter	Total
	(dollars in millions)						
Long-term debt	$ 31.0	$ 182.8	$ 31.0	$ 231.0	$ 360.3	$ 1,029.6	$ 1,865.7
Power and other purchase commitments	70.4						70.4
Other operating leases	4.2	4.2	4.0	3.5	1.1		17.0
Right-of-way(1)	1.8	1.7	1.7	1.8	1.8	44.7	53.5
Product purchase obligations(2)	62.8	59.9	36.6	31.8	28.0	116.7	335.8
Service contract obligations(3)	12.4	10.5	5.3	3.2			31.4
Total	$ 182.6	$ 259.1	$ 78.6	$ 271.3	$ 391.2	$ 1,191.0	$ 2,373.8

(1) Right-of-way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipeline systems, which has been estimated to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2010.

(2) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(3) The transportation service obligations represent the minimum payment amounts for firm transportation capacity we have reserved on third-party pipelines.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. Extensive volume growth in the areas served by our East Texas system necessitates the construction of additional pipeline capacity to transport these volumes to alternate natural gas markets. Additionally, anticipated growth in western Canadian oil sands production and the need to reach newer markets has prompted the Southern Access project on our Lakehead system. In 2006, we expect to spend approximately $530 million on these projects with the expectation of realizing additional cash flows as these projects are completed and placed in service. At December 31, 2005, we had $64.0 million in estimated outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2006.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

In 2006, we anticipate our capital expenditures to approximate the following in millions:

System enhancements	$ 430
Core maintenance activities	45
Southern Access expansion	190
East Texas expansion	340
	$ 1,005

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to the East Texas expansion and Southern Access projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper, borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

The Southern Access and East Texas expansion projects have strong support from shippers, and upon completion each project will have stable cash flows. We have received indications that these projects can be readily financed. We are currently in discussions with our commercial bankers to structure and implement bridge credit facilities that will be required to finance the construction. This incremental bridge credit capacity may also be used to support a temporary expansion of our commercial paper program. The bridge credit facilities will be refinanced with permanent capital at key milestone dates for each project.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

Acquisitions

We continue to assess various acquisition and expansion opportunities to pursue our strategy for growth. However, the market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts on development of our existing pipeline systems. Additionally, we may pursue opportunities to divest of any non-strategic assets as conditions warrant.

We expect that the funds needed to achieve growth through acquisitions will be obtained through issuances of commercial paper, term debt and additional partnership interests.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments at December 31, 2005 for each of the indicated calendar years:

	Notional	2006	2007	2008	2009	2010	2011	2012
		(dollars in millions)						
Swaps								
Natural gas(1)	498,796,627	$ (84.3)	$ (58.0)	$ (46.8)	$ (33.4)	$ (25.8)	$ (21.2)	$ (4.8)
NGL(2)	6,942,833	(29.7)	(22.5)	(7.2)	(0.6)	(0.3)		
Crude(2)	1,376,479	(7.6)	(7.9)	(5.2)	(1.0)	(0.1)		
Options calls								
Natural gas(1)	2,191,000	(2.3)	(2.0)	(1.7)	(1.4)	(1.1)	(1.0)	
Options puts								
Natural gas(1)	1,826,000						0.1	
Totals		$ (123.9)	$ (90.4)	$ (60.9)	$ (36.4)	$ (27.3)	$ (22.1)	$ (4.8)

(1) Notional amounts for natural gas are recorded in millions of British thermal units (MMBtu).

(2) Notional amounts for NGL and Crude are recorded in Barrels (Bbl).

Operating Activities

Net cash provided by operating activities was $267.1 million in 2005 compared with $245.4 million in 2004. Improved operating cash flow was the result of operating income contributions from the gathering and processing assets we acquired in north Texas, which was partially offset by lower deliveries on the Lakehead system. The remaining changes in cash from operating activities were due to changes in the operating assets and liabilities from increased natural gas prices in 2005 and general timing differences in the collection on and payment of our current accounts.

Investing Activities

Net cash used in our investing activities was $437.1 million for the year ended December 31, 2005, compared with $419.1 million for the prior year. The $18 million increase in funds utilized in investing activities was primarily attributable to the following items:

- The dollar value of our acquisitions in 2005 was higher compared with 2004, effectively increasing our cash outflows by $45.4 million. During 2005, we acquired natural gas gathering and processing assets in North Texas for $164.6 million, a natural gas pipeline with interconnects to our Anadarko system for $20.1 million, and other small assets for $1.7 million. In 2004 our asset acquisitions primarily consisted of our Mid-Continent and Palo Duro assets and several other smaller assets for $141.0 million.

- We also had increased cash outflows associated with expansion and growth opportunities of existing assets during 2005 of $56.0 million, as compared to 2004. During 2005, we spent $344.8 million for capital expenditures including core maintenance and enhancement projects compared to $288.8 million in 2004. Our core maintenance capital expenditures increased to $33.0 million for 2005 compared with $31.6 million for 2004, due to the expansion and growth of our existing assets. Our enhancement capital spending increased to $311.8 million in 2005 from $257.2 million in 2004. This increase is primarily due to the 107-mile expansion of our East Texas System, which was completed in June 2005, and several smaller projects to expand our existing natural gas transmission and processing capacity, and increase our crude oil storage facilities in the mid-continent market.

In December 2005, we sold for $105.4 million in cash a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million and recognized a gain on the sale of approximately $18.1 million. The facilities we sold represent non-strategic assets within our Natural Gas segment. In connection with this sale, we paid approximately $16.3 million to settle natural gas and NGL hedges associated with the natural gas and NGL produced by these assets. We had previously recognized unrealized losses associated with the natural gas hedges that were realized upon settlement.

Financing Activities

Net cash provided by financing activities was $181.5 million in 2005, compared with $187.6 million in 2004. The decrease in cash provided by financing activities of $6.1 million is attributable to a greater amount of distributions to our partners, no new issuances of senior notes during 2005, offset by a larger amount of proceeds received from unit issuances and increased net issuances of commercial paper and fewer net repayments on the Credit Facility.

During 2005, we had net commercial paper issuances of $330.0 million program which include gross issuances of $2,808.0 million and gross repayments of $2,478.0 million.   We began utilizing the commercial paper program in April 2005. We used proceeds from our issuances of commercial paper to repay amounts outstanding under our Credit Facility. We made net repayments of $175.0 million on our Credit Facility including borrowings and repayments of $565.0 million representing net non-cash settlements with the parties to our Credit Facility. During 2004, we made net repayments of $280.0 million on our Credit Facility including borrowings and repayments of $1,573.0 million representing net non-cash settlements with the parties to our Credit Facility. Additionally during 2004, we received proceeds of $495.4 million, excluding issuance costs and discounts totaling $4.6 million, from the issuance of $500 million in aggregate principle amount of our senior notes. We used a portion of the proceeds from our senior note issuance to repay amounts outstanding under our credit facilities which we initially borrowed to fund our capital expenditures for expansion projects and acquisitions. We have historically borrowed on our Credit Facility for short-term operating activities and to fund capital expenditures for expansion projects and acquisitions. However, in the second quarter of 2005 we began issuing commercial paper as a more economical source of short-term capital than our Credit Facility. During 2005 and 2004, we also repaid $31 million on our First Mortgage Notes.

During 2005, we also received approximately $268.6 million of net proceeds from the issuance of 5.6 million Class A common units, compared to net proceeds of $194.2 million from the issuance of 4.1 million Class A common units in 2004. Cash distributions to partners increased to $210.6 million in 2005 from $191.0 million in 2004 due to:

- An increase in the number of units outstanding; and
- An increase in the general partner incentive distributions, as a result of the increased cash distributions to our common unitholders.

Cash Distributions

We make quarterly distributions to our General Partner and the holders of our common units, an amount equal to our available cash, which generally is defined to mean for any calendar quarter the sum of all of our cash receipts plus net reductions to reserves less all of our cash disbursements and net changes to reserves. These reserves are retained to provide for the proper conduct of our business, to stabilize distributions of cash to unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of the General Partner under a delegation of control agreement, computes the amount of our available cash.

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our common units, the number of i-units owned by Enbridge Management and the percentage of total units in us owned by Enbridge Management increases automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management s shares and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management s listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management s shares multiplied by the number of shares outstanding on the record date.

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units that are issued when a distribution of cash is made to the General Partner and owners of common units is treated as distribution of available cash, even though the i-unit holder will not receive cash. We retain the cash for use in our operations. During 2005, we distributed a total of 802,539 i-units through quarterly distributions to Enbridge Management, compared with 840,239 in 2004. We retained $41.5 million in 2005 related to the i-unit distributions compared with $38.3 million in 2004.

We expect our annual cash distribution rate for fiscal year 2006 to remain consistent with the declared annual distribution per unit rate of $3.70 for the years ended December 31, 2005 and 2004. We expect that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, we may temporarily borrow under our Credit Facility for the purpose of paying cash distributions until the full impact of assets being developed on operations is realized.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Subsequent Events

Cash Distribution

On January 30, 2006, Enbridge Management s Board of Directors declared a distribution payable to our partners on February 14, 2006. The distribution was paid to unitholders of record as of February 6, 2006, of our available cash of $67.6 million at December 31, 2005, or $0.925 per common unit. Of this distribution, $56.6 million was paid in cash, $10.8 million was distributed in i-units to i-unit holders and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our selection and application of accounting policies is an important process that has developed as our business activities have evolved and as new accounting pronouncements have been issued. Accounting decisions generally involve an interpretation of existing accounting principles and the use of judgment in applying those principles to the specific circumstances existing in our business. We make every effort to comply with all applicable accounting principles and believe the proper implementation and consistent application of these principles is critical. However, not all situations we encounter are specifically addressed in the accounting literature. In such cases, we must use our best judgment to implement accounting policies that clearly and accurately present the substance of these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them and consulting with experts about the appropriate interpretation and application of the accounting literature to these situations.

In addition to the above, certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and other sources we believe to be reliable. While we believe our estimates are appropriate, actual results can and often do differ from these estimates. Any effect on our business, financial position, results of operations and cash flows resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing accounting literature or in the development of estimates that affect our consolidated financial statements. Our management has discussed the development and selection of the critical accounting policies and estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent liabilities with the Audit, Finance & Risk Committee of Enbridge Management s Board of Directors.

Revenue Recognition and the Use of Estimates for Revenues and Cost of Natural Gas

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For our natural gas business, we must estimate our current month revenue and cost of natural gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month s estimate to equal the prior month s actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each of the years ended December 31, 2005, 2004 and 2003. We believe that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of our processes.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced or improved; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include first-time high resolution integrity tool runs, the costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of the pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Recent regulatory guidance issued by the FERC will require us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation s Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We are adopting this guidance prospectively for our SFAS No. 71 companies only, namely, our UTOS, Midla, AlaTenn and KPC natural gas transmission systems. Consistent with our prior practice, costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition will continue to be capitalized for our FERC-regulated and non-regulated pipeline systems. Additionally, for our non-regulated pipelines and our FERC-regulated crude oil pipelines that are not eligible to apply the provisions of SFAS No. 71, we will continue to capitalize first-time crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects, consistent with our historical policy. Subsequent work of this nature is expensed as incurred. Our FERC-regulated crude oil pipelines will expense items 1-4 listed above for regulatory reporting purposes. We do not expect our implementation of this regulation to significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost and depreciate our assets over the lesser of their estimated useful lives or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve using the group method. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a significant separately identifiable group of assets, such as a processing plant, treating facility or a pipeline system are sold, we will recognize a gain or loss in our Consolidated Statements of Income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Income.

Assessment of Recoverability of Goodwill and Intangibles

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually as of the end of the second quarter or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent five-year plan, which we use to manage the business.

Preparation of forecast information for use in our five-year plan involves significant judgments. Actual results can, and often do, differ from the projections and assumptions we make in preparing these forecasts. These changes can have a negative impact on our estimates of impairment, which could result in charges to income. In addition, further changes in the economic and business environment can affect our original and ongoing assessments of potential impairment.

Other intangible assets consist of natural gas purchase and sale customer contracts, and natural gas supply opportunities, which we amortize on a straight-line basis over the weighted average useful life of the underlying assets, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. If there are changes to any of our estimates and assumptions, actual results may differ.

Asset Retirement Obligations

The provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*, require us to record a liability for the fair value of our asset retirement obligations, on a discounted basis, in the period in which the liability is incurred, which is typically at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. The provisions also require that we capitalize the costs associated with the asset retirement obligations as part of the carrying cost of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the retirement obligation due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for asset retirement obligations when assets are taken out of service or otherwise abandoned.

The provisions of Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* (FIN 47) require us to recognize a liability and related asset, consistent with SFAS No. 143, for the fair value of conditional asset retirement obligations that we can reasonably estimate. FIN 47 also provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. Our implementation of FIN 47 did not have a material impact effect on our consolidated financial statements.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate an abandonment retirement obligation cost. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management s intent, or the asset s estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumer/refinery consumption. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates and commodity prices of natural gas, NGLs, condensate and fractionation margins. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities and fix the interest rate on our variable rate debt.

The accounting treatment for our derivative financial instruments is determined by the guidance of SFAS No. 133 and is dependent on each instrument s intended use, how it is designated and the extent to which the derivative financial instrument is effective in hedging the risk that it is intended to mitigate. To qualify for hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Derivative financial instruments qualifying for hedge accounting treatment that we use can be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. Cash flow hedges are entered to hedge the variability in cash flows related to a forecasted transaction. Fair value hedges are entered to hedge the value of a recognized asset or liability. Cash flow and fair value hedges are considered highly effective if they are able to substantially offset (i.e., more than 80 percent) the changes in cash flow or fair value of the risk that is being hedged. The extent to which a derivative financial instrument designated as a hedge does not offset the changes in cash flow or fair value of the risk being hedged is considered ineffective. At inception and on an ongoing basis we assess whether the derivative financial instruments we use in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items.

All of our derivative financial instruments are recorded in our Consolidated Financial Statements at fair market value as current and long-term assets or liabilities on a net basis by counterparty and are adjusted each period for changes in the fair market value. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Derivative financial instruments that we designate and qualify as cash flow or fair value hedges under the requirements of SFAS No. 133, receive hedge accounting treatment for the effective portion of the derivative financial instrument. Under hedge accounting, any unrealized gain or loss in fair market value of the effective portion of a derivative financial instrument designated as a cash flow hedge is recorded as an asset or liability with an offset deferred in Accumulated other comprehensive income (OCI), a component of Partners Capital, until the underlying hedged transaction occurs. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges of forecasted commodity purchases and sales are included in Cost of natural gas and cash flow hedges of forecasted interest payments are included in Interest on our Consolidated Statements of Income in the period the hedged transaction occurs. Under hedge accounting, the realized and unrealized gain or loss in the fair market value of a derivative financial instrument designated as a fair value hedge is recorded as an asset or a liability with the offset recorded in our Consolidated Statements of Income as a component of Cost of natural gas for fair value hedges of our commodities and as a component of interest expense for fair value hedges of our indebtedness both of which are offset by the changes in the fair market value of the underlying hedged item.

Under the guidance of SFAS No. 133, the changes in fair market value, both realized and unrealized gains and losses, of derivative financial instruments that 1) do not qualify for hedge accounting, 2) are not designated as hedges and 3) are ineffective, are recognized each period in our Consolidated Statements of Income. These changes in fair market value are recognized as a component of Cost of natural gas for our commodity derivative financial instruments and as a component of interest expense for derivative financial instruments of our interest rates. We refer to the accounting treatment for derivative financial instruments that do not qualify for hedge accounting as mark-to-market accounting. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment.

Our cash flow is only affected to the extent the actual derivative contract is settled by 1) making or receiving a payment to/from the counterparty; or 2) by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the physical transaction that underlies the derivative financial instrument occurs.

Gains and losses that we have deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter.

One of the primary factors that can affect our operating results each period is the price assumptions we use to value our derivative financial instruments. To the extent that these derivative financial instruments are ineffective or do not qualify for hedge accounting treatment under the requirements of SFAS No. 133, they are accounted for using the mark-to-market method of accounting and any change in the fair market value is reflected in our Consolidated Statements of Income as a component of Cost of natural gas or Interest expense, depending on whether the derivative financial instrument relates to a commodity or interest rate. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our consolidated financial statements change quarterly as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Commitments, Contingencies and Environmental Liabilities

We accrue reserves for contingent liabilities, including environmental remediation and clean-up costs, when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors, and include estimates of associated legal costs. These estimates also consider prior experience remediating contaminated sites, other companies clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances and any revisions are reflected in our earnings in the period in which they are reasonably determinable. We evaluate recoveries from insurance coverage separately from our liability and, when recovery is reasonably assured, we record and report an asset separately from the associated liability in our financial statements. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial cost and future liabilities.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Both internal and external legal counsel evaluate our potential exposure to adverse outcomes. When a range of probable loss can be estimated, we accrue the most likely amount, or at least the minimum of the range of probable loss. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to review our estimates, income may be affected.

Oil Over/Short Balance and Oil Measurement Gains/Losses

Oil over/short balance and oil measurement gains/losses are inherent in the transportation of crude oil due to evaporation, measurement differences and blending of commodities in transit in addition to other factors. We estimate our oil measurement gains/losses and our oil over/short balance based on mathematical calculations and physical measurements, which include assumptions about the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of our oil over/short balance or revision of our oil measurement gain/loss estimates. We include the oil measurement gains/losses in our operating and administrative expenses on our Consolidated Statements of Income and the oil over/short balance in Accounts payable and other in the Consolidated Statements of Financial Position if the balance is a liability and in Inventory if the balance is in an asset position.

Operational Balancing Agreements and Natural Gas Imbalances

We record payables and receivables associated with our natural gas pipeline operational balancing agreements and natural gas imbalances monthly when a customer delivers more or less natural gas into our pipelines than they remove. These balances are either settled on a cash basis or are carried by the pipelines and shippers on an in-kind basis. We primarily estimate the value of the imbalances at month-end spot prices based on published third-party indices for the locations where the imbalances are derived using the best available third party and internal volume information. If there is a change to these estimates and assumptions, actual results may differ.

RECENT ACCOUNTING DEVELOPMENTS

Accounting Changes and Error Corrections

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. Under this statement, voluntary changes in accounting principle are required to be applied retrospectively for the direct effects of a change to prior periods financial statements, unless such application is impracticable. Retrospective application refers to reflecting a change in accounting principle in the financial statements of prior periods as if the principle had always been used. When retrospective application is determined to be impracticable, this statement requires the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective treatment is practicable with a corresponding adjustment to the opening balance of retained earnings. This statement retains the guidance in APB Opinion No. 20 for reporting the corrections of errors and changes in accounting estimates. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, with early adoption permitted. Our adoption of this statement will affect our consolidated financial statements for any changes in accounting principle we may make in the future, and new pronouncements we adopt that do not provide transition provisions.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation s Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, and will be applied prospectively to our SFAS No. 71 companies. We do not expect our implementation of this regulation to significantly affect our financial position, results of operations or cash flows.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

We utilize both fixed and variable interest rate debt, and are exposed to market risk resulting from the variable interest rates on our Credit Facility and the frequent changes in interest rates when we re-issue maturing commercial paper. To the extent that we frequently issue and re-issue commercial paper at short-term interest rates and have amounts drawn under our credit facilities at floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing commercial paper and floating-rate bank debt with long-term fixed rate debt and through the use of interest rate derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments .

The table below summarizes the carrying value and fair value of our third-party debt obligations and interest rate derivative financial instruments as of December 31, 2005 and 2004. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Within this table positive balances represent liabilities and bracketed amounts represent assets.

	December 31, 2005									December 31, 2004	
	Average Interest Rate	Expected Fiscal Year of Maturity of Carrying Amounts 2006	2007	2008	2009	2010	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
		(dollars in millions)									
Liabilities											
Fixed Rate:											
First Mortgage Notes	9.15 %	$ 31.0	$ 31.0	$ 31.0	$ 31.0	$ 31.0	$ 31.0	$ 186.0	$ 207.9	$ 217.0	$ 256.8
Senior notes due 2009	4.00 %				199.9			199.9	193.0	199.9	199.2
Senior notes due 2012	7.90 %						99.9	99.9	113.8	99.9	120.1
Senior notes due 2013	4.75 %						199.8	199.8	190.8	199.7	197.1
Senior notes due 2014	5.35 %						199.9	199.9	196.7	199.9	203.2
Senior notes due 2018	7.00 %						99.8	99.8	111.4	99.8	117.4
Senior notes due 2028	7.125 %						99.8	99.8	113.0	99.8	119.3
Senior notes due 2033	5.95 %						199.7	199.7	193.1	199.7	200.3
Senior notes due 2034	6.30 %						99.8	99.8	100.8	99.7	104.1
Variable Rate:											
Commercial paper	4.36 %					329.3		329.3	329.3		
Credit Facility	n/a									175.0	175.0

	December 31, 2005									December 31, 2004	
		Expected Fiscal Year of Maturity of Notional Amounts									
	Average Interest Rate	2006	2007	2008	2009	2010	Thereafter	Total Notional Amount	Fair Value	Notional Amount	Fair Value
Interest Rate Derivatives											
Interest Rate Swaps:											
Variable to Fixed	LIBOR	150.0					125.0	275.0	(3.0)	125.0	0.9
Average Pay Rate	3.72 %	3.20 %					4.34 %	3.72 %		4.35 %	
Fixed to Variable	4.75 %						125.0	125.0	(0.6)	125.0	(4.6)
Average Pay Rate	LIBOR-0.21 %						LIBOR-0.21 %	LIBOR-0.21 %		LIBOR-0.21 %	

Our floating to fixed rate interest rate swaps maturing in 2006 qualify for and have been designated cash flow hedges of interest payments on $150 million of our variable rate indebtedness and therefore, the changes in fair value of these derivatives are recorded as an increase or decrease in Accumulated other comprehensive income. The floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 do not qualify as cash flow or fair value hedges and as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

COMMODITY PRICE RISK

Our net income and cash flows are also subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at December 31, 2005 and December 31, 2004, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At December 31, 2005						At December 31, 2004	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	**Volumes**(1)	**Receive**	**Pay**	**Asset**	**Liability**	**Asset**	**Liability**
Contracts maturing in 2006								
Swaps								
Receive variable /pay fixed	Natural Gas	145,258,496	$ 9.78	$ 7.19	$ 380.6	$ (11.7)	$ 4.2	$ (7.8)
Receive fixed /pay variable	Natural Gas	152,649,441	7.17	10.20	14.5	(467.8)	7.8	(23.3)
	NGL	2,702,460	29.08	40.35		(29.7)	0.5	(4.1)
	Crude	417,725	44.58	63.15	0.2	(7.8)	0.4	(1.4)
Receive variable /pay variable	Natural Gas	14,482,911	9.70	9.70	5.2	(5.2)		(0.2)
Options								
Calls (written)	Natural Gas	365,000	10.78	4.31		(2.0)		(1.8)
Contracts maturing in 2007								
Swaps								
Receive variable /pay fixed	Natural Gas	53,882,446	9.68	7.48	112.0	(1.0)	0.6	(8.2)
Receive fixed /pay variable	Natural Gas	60,540,090	7.23	10.22	0.5	(170.0)	8.5	(15.8)
	NGL	2,698,810	28.03	36.99		(22.5)	0.4	(4.0)
	Crude	388,680	42.05	63.99		(7.9)	0.2	(1.3)
Receive variable /pay variable	Natural Gas	3,579,170	9.97	9.79	0.7	(0.1)		
Options								
Calls (written)	Natural Gas	365,000	10.25	4.31		(2.0)		(1.5)
Puts	Natural Gas	365,000	10.25	3.40				
Contracts maturing in 2008								
Swaps								
Receive variable /pay fixed	Natural Gas	10,236,065	9.23	7.23	18.5			(1.9)
Receive fixed /pay variable	Natural Gas	21,922,508	6.17	9.56		(66.3)	2.3	(12.2)
	NGL	729,438	25.59	36.78		(7.2)	0.7	(0.2)
	Crude	323,699	44.18	62.29		(5.2)	0.5	
Receive variable /pay variable	Natural Gas	3,294,000	8.95	8.59	1.0			
Options								
Calls (written)	Natural Gas	366,000	9.37	4.31		(1.7)		(1.2)
Puts	Natural Gas	366,000	9.37	3.40			0.1	
Contracts maturing in 2009								
Swaps								
Receive fixed /pay variable	Natural Gas	11,497,500	5.02	8.55		(34.5)		(9.8)
	NGL	494,575	32.83	34.24		(0.6)		
	Crude	155,125	53.13	61.01		(1.0)		
Receive variable /pay variable	Natural Gas	4.197,500	8.13	7.83	1.1			
Options								
Calls (written)	Natural Gas	365,000	8.55	4.31		(1.4)		(1.1)
Puts	Natural Gas	365,000	8.55	3.40			0.2	

Contracts maturing in 2010								
Swaps								
Receive fixed /pay variable	Natural Gas	8,760,000	4.15	7.80	0.1	(25.9)		(8.2)
	NGL	317,550	30.60	31.96		(0.4)		
	Crude	91,250	59.00	59.68		(0.1)		
Options								
Calls (written)	Natural Gas	365,000	7.91	4.31		(1.1)		(0.9)
Puts	Natural Gas	365,000	7.91	3.40			0.2	
Contracts maturing after 2010								
Swaps								
Receive fixed /pay variable	Natural Gas	8,496,500	3.62	7.64		(26.1)		(10.1)

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Options							
Calls (written)	Natural Gas	365,000	7.46	4.31	(0.9)		(0.9)
Puts	Natural Gas	365,000	7.46	3.40		$ 0.2	

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at December 31, 2005 and December 31, 2004, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

All derivative financial instruments are recorded in our consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value (mark-to-market). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* (SFAS No. 133), if a derivative financial instrument does not qualify as a hedge or is not designated as a hedge, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and is recorded in Cost of natural gas for commodity derivatives and interest expense for interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to/from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs (e.g., purchase or sale of natural gas or interest payment).

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, a change in the fair market value is deferred in Accumulated other comprehensive income (OCI), a component of Partners Capital, until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges and qualify for hedge accounting are included in Cost of natural gas in the period the hedged transaction occurs. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a fair value hedge of the change in fair market value of an underlying asset or liability, the gain (loss) resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain (loss) resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge s change in fair market value will be recorded in earnings as the amount that is not offset by the gain (loss) on the change in fair market value of the underlying asset or liability. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in interest expense. Similar to derivative financial instruments designated as cash flow hedges, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered non-qualified under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation** In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. **Storage** In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur because we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

3. **Natural Gas Collars** In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery points for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the second quarter of 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of Income from OCI. Going forward, the discontinued derivative financial instruments are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out during the second quarter.

The following table presents the unrealized losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value losses	**December 31, 2005 (in millions)**	**December 31, 2004**	**December 31, 2003**
Natural Gas segment			
Ineffectiveness	$ 2.5	$ 1.1	$
Non-qualified hedges	5.6		
Marketing			
Non-qualified hedges	41.3	2.1	0.3
Discontinuance	9.0		
Derivative fair value losses	$ 58.4	$ 3.2	$ 0.3

De-designation and Settlement of Derivatives

In connection with the sale of assets, as discussed in Note 3 to the Consolidated Financial Statements, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with these natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that were qualified for and designated as cash flow hedges of forecasted sales of 273 Bbl/d of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bbl/d of NGLs through 2007.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	December 31, 2005	December 31, 2004
	(in millions)	
Receivables, trade and other	$ 5.8	$ 8.2
Other assets, net	4.2	10.1
Accounts payable and other	(129.2)	(45.9)
Other long-term liabilities	(243.0)	(99.6)
	$ (362.2)	$ (127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to December 31, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership s portfolio of derivative financial instruments is largely comprised of long-term fixed price sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in our OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in OCI are unrecognized losses of approximately $8.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These unrealized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the twelve months ended December 31, 2005, and 2004 we reclassified unrealized losses of $33.8 million and $12.6 million from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled. We estimate that approximately $83.7 million of OCI representing unrealized net losses on cash flow hedging activities at December 31, 2005, will be reclassified to earnings during the next twelve months.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated BBB+ or better by the major credit rating agencies.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the notes thereto and the independent registered public accounting firm s report thereon, and unaudited supplementary information, appear beginning on page F-2 of this report, and are incorporated by reference. Reference should be made to the Index to Financial Statements, Supplementary Information and Financial Statement Schedules on page F-1 of this report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Management of the Partnership has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2005. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, management of the Partnership relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. No changes in our internal control over financial reporting were made during the three months ended December 31, 2005, that would materially affect our internal control over financial reporting.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management s Report on Internal Control Over Financial Reporting

Management of Enbridge Energy Partners, L.P. and its consolidated subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership s internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership s financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

The Partnership s internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Partnership;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with the authorization of the Partnership s management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

The Partnership s internal control over financial reporting may not prevent or detect all misstatements because of its inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or deterioration in the degree of compliance with our policies and procedures.

Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2005, based on the framework established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2005.

Management s assessment of the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report beginning on page F-2.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The Partnership is a limited partnership and has no officers or directors of its own. Set forth below is certain information concerning the directors and executive officers of the General Partner and of Enbridge Management as the delegate of the General Partner under a Delegation of Control Agreement among the Partnership, the General Partner and Enbridge Management. All directors of the General Partner are elected annually and may be removed by Enbridge Pipelines, as the sole stockholder of the General Partner. All directors of Enbridge Management were elected and may be removed by the General Partner, as the sole holder of Enbridge Management s voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the respective boards of directors of the General Partner and Enbridge Management. All directors and officers of the General Partner hold identical positions in Enbridge Management.

Name	Age	Position
J.A. Connelly	59	Director
P.D. Daniel	59	Director
E.C. Hambrook	68	Director
M.O. Hesse	63	Director
G.K. Petty	64	Director
D.C. Tutcher	56	President and Director
J.R. Bird	56	Group Vice President Liquids Transportation and Director
L.A. Zupan	50	Vice President Liquids Transportation Operations
M.A. Maki	41	Vice President Finance
T.L. McGill	51	Vice President Commercial Activity & Business Development & Chief Operating Officer
A.D. Meyer	49	Vice President Liquids Transportation Technology
R.L. Adams	41	Vice President Operations and Technologies
D.V. Krenz	54	Vice President
V.D. Yu	39	Treasurer
J.L. Balko	40	Controller
E.C. Kaitson	49	Assistant Secretary
B.A. Stevenson	50	Corporate Secretary

J.A. Connelly was elected a director of the General Partner in January 2003 and serves as the Chairman of its Audit, Finance & Risk Committee. Mr. Connelly served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001. Mr. Connelly is a business consultant providing executive management consulting services.

P.D. Daniel was elected a director of the General Partner in July 1996 and served as its President from July 1996 through October 1997. Mr. Daniel has served as President of Enbridge since September 2000 and as Chief Executive Officer of Enbridge since January 2001. Prior to that time Mr. Daniel also served as President & Chief Operating Officer Energy Delivery of Enbridge from June 1998 to December 2000. He currently serves as a director of EnCana Corporation.

E.C. Hambrook was elected a director of the General Partner in January 1992 and serves on its Audit, Finance & Risk Committee. Mr. Hambrook serves as Chairman of the board of directors of the General Partner. Mr. Hambrook has served as President of Hambrook Resources, Inc. since its inception in 1991. Hambrook Resources, Inc. is a real estate investment, marketing and sales company.

M.O. Hesse was elected a director of the General Partner in March 2003 and serves as a member of its Audit, Finance & Risk Committee. Ms. Hesse was President and CEO of Hesse Gas Company from 1990 through 2003. She served as Chairman of the U.S. Federal Energy Regulatory Commission from 1986 to 1989. Ms. Hesse also served as Senior Vice President, First Chicago Corporation and Assistant Secretary for Management and Administration, U.S. Department of Energy. She currently serves as a director of Arizona Public Service Company, Pinnacle West Capital Corporation, and Terra Industries, Inc.

G.K. Petty was elected a director of the General Partner in February 2001 and serves on its Audit, Finance & Risk Committee. Mr. Petty has served as a director of Enbridge since January 2001. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty is a business consultant providing executive management consulting services to the telecommunications industry.

D.C. Tutcher was elected a director and President of the General Partner in June 2001. He also currently serves as Group Vice President, Transportation South of Enbridge. He was previously Chairman of the Board, President and Chief Executive Officer of Midcoast Energy Resources, Inc. from its formation in 1992 until it was acquired by Enbridge on May 11, 2001.

J.R. Bird served as a director of the General Partner from September 2000 to January 2003 and was reelected as a Director in October 2003. He was elected Group Vice President, Liquids Transportation of the General Partner in May 2005 and Vice President, Liquids Transportation in January 2003. He served as President from September 2000 until June 2001. He has also served as Group Vice President, Liquids Pipelines since May 2005 prior to which he was Group Vice President, Transportation North of Enbridge since May 2001 and President of Enbridge Pipelines since September 2000. Prior to that time he served as Group Vice President, Transportation from September 2000 through April 2001 and as Senior Vice President, Corporate Planning and Development of Enbridge from August 1997 through August 2000.

L.A. Zupan was elected Vice President, Liquids Transportation Operations of the General Partner in July 2004. Prior to that he has served as Vice President, Development & Services for Enbridge Pipelines since 2000 and prior to that as Director, Information Technology.

M.A. Maki was elected Vice President, Finance of the General Partner in July 2002. Prior to that time, he served as Controller of the General Partner since June 2001, and prior to that, as Controller of Enbridge Pipelines since September 1999.

T.L. McGill was elected Vice President, Commercial Activity and Business Development of the General Partner in April 2002 and Chief Operating Officer in July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

A.D. Meyer was elected Vice President, Liquids Transportation Technology, of the General Partner in July 2003. He also continues to serve as Vice President, Technology, Enbridge Pipelines since his appointment in July 1999 and as President, Gateway Pipeline Inc. since his appointment in June 2005. Prior to that time he served as President, Enbridge Pipelines (Athabasca) Inc. from October 1997 to July 1999 and as Vice President, Liquids Marketing with Enbridge for the same period.

R.L. Adams was elected Vice President, Operations and Technologies of the General Partner in April 2003. Prior to his current position, he was Director of Technology & Operations for the General Partner since 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for Ocensa/Enbridge in Bogota, Columbia from 1997 to 2001.

D.V. Krenz was elected Vice President of the General Partner in January 2005. Prior to that, he was President of Shell Gas Transmission, LLC (previously Shell Gas Pipelines Co.) from March 1996 to December 2004.

V. D. Yu was appointed as Treasurer of the General Partner in July 2005 and is also an Assistant Treasurer of Enbridge. Since July 2002 he was Director Financial Management at Enbridge and previously Manager, Capital Markets and Risk Management.

J.L. Balko was elected Controller of the General Partner in April 2003. Prior to that time, she served as Chief Accountant of the General Partner from October 1999 to April 2003.

E.C. Kaitson was elected Assistant Secretary of the General Partner in July 2004. He served as Corporate Secretary of the General Partner from October 2001 to July 2004. He also currently serves as Associate General Counsel, of Enbridge. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until Enbridge acquired it on May 11, 2001.

B.A. Stevenson was elected Corporate Secretary of the General Partner in July 2004. Between 2000 and 2004 Mr. Stevenson held management positions with Reliant Energy, Inc. and Arthur Andersen LLP. Prior to that Mr. Stevenson was General Counsel & Corporate Secretary of Alberta Natural Gas Company Ltd, a Canadian gas processing and transmission company, that was acquired by TransCanada Pipelines.

(b) SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC, reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. Based solely on the review of the reports furnished to us, we believe that, during fiscal year 2005, all Section 16(a) filing requirements applicable to Enbridge Management s directors, officers, and greater than 10% beneficial owners were met.

(c) GOVERNANCE MATTERS

We are a controlled company, as that term is used in NYSE Rule 303A, because all of our voting shares are owned by the General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner s board of directors.

The NYSE listing standards require our CEO to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on October 14, 2005.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management has an Audit, Finance & Risk Committee (the Audit Committee) comprised of four board members who are independent as the term is used in Section 10A of the Exchange Act of 1934, as amended. None of these members are relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are M.O. Hesse, E.C. Hambrook, G.K. Petty and J.A. Connelly. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the Board of Directors.

The charter of the Audit Committee is available on our website at *www.enbridgepartners.com*. The Charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us.

Enbridge Management s Board of Directors has determined that M.O. Hesse, E.C. Hambrook and J.A. Connelly qualify as Audit Committee financial experts as defined in Item 401(h) of SEC Regulation S-K and are independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act.

Enbridge Management s Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by writing in care of Chairman, Audit Committee, c/o Enbridge Energy Management, L.L.C., 1100 Louisiana, Suite 3300, Houston TX 77002.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

The Partnership has adopted a Code of Ethics applicable to our senior financial officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. We intend to post on our website any amendments to or waivers of our Code of Ethics for Senior Financial Officers. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

We also have a Statement of Business Conduct applicable to all of our employees, officers and directors. A copy of the Statement of Business Conduct is available on our website at *www.enbridgepartners.com*. We intend to post on our website any amendments to or waivers of our Statement of Business Conduct. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston TX 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how the Board should function and the Board s position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at *www.enbridgepartners.com*. We intend to post on our website any amendments to our Corporate Governance Guidelines. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston TX 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. J.A. Connelly or E.C. Hambrook serve as the presiding director at those executive sessions. Persons wishing to communicate with the Company s independent directors may do so by writing in care of Chairman, Board of Directors, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

Item 11. Executive Compensation

The following table sets forth the annual, long-term and other compensation for all services provided in all capacities to Enbridge Management and the Partnership for the fiscal years ended December 31, 2005, 2004 and 2003 of the Chief Executive Officer and four of our other executive officers with the highest salary and bonus compensation charged to Enbridge Management and Partnership in the 2005 fiscal year (the Named Executive Officers). The Partnership bears an allocable portion of these officers total compensation that is based on the approximate percentage of time each of these officers devote to Enbridge Management and the Partnership. The other affiliates of Enbridge, to whom these officers also render services, bear the remainder of the compensation expenses of these officers.

Summary Compensation Table

Name & Principal Position	**Year**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation**(1)(2) ($)	**Restricted Stock Award(s) ($)**	**Securities Underlying Options/ SARs**(4) (#)	**LTIP Payouts ($)**	**All Other Compensation**(3) ($)	**Approximate Percentage of Time Devoted to Enbridge Management and the Partnership**
D.C. Tutcher	2005	343,750	235,000	30,000		34,000		17,897	90
President	2004	322,000	270,000	30,000		17,000		12,350	
	2003	309,750	235,000	35,000		50,000		10,000	
T.L. McGill	2005	267,750	143,894	20,000		20,400		12,886	90
Vice President	2004	231,385	126,500	20,000		20,000		11,044	
Commercial	2003	221,000	89,800	20,000		23,200		6,361	
Activity & Business Development									
E.C. Kaitson	2005	182,685	54,839	10,000		11,600		11,384	90
Assistant Secretary	2004	174,055	59,900	10,000		6,500		10,643	
and Associate General	2003	168,000	35,400	10,000		5,900		8,375	
Counsel									
M.A. Maki	2005	197,500	84,840	20,000		11,400		10,288	90
Vice President	2004	171,365	87,300	20,000		15,000		9,444	
Finance	2003	161,750	71,400	20,000		16,700		7,100	
R.L. Adams	2005	176,070	75,600	20,000		10,800		8,950	90
Vice President	2004	161,960	81,600	20,000		10,000		8,339	
Operations and	2003	151,000	54,100	26,229		7,500		7,568	
Technology									

(1) Amounts in this column include: the flexible perquisites allowance (as described in Note 2 below), flexible credits paid as additional compensation (as described in Note 2 below), one-time payments for termination benefits, and the taxable benefit from loans by Enbridge, which were granted for relocation or hiring incentive purposes (and amounts reimbursed for the payment of taxes relating to such benefit).

(2) Effective July 1, 2001, Enbridge adopted a flexible benefit program pursuant to which employees receive an amount of flex credits based on their family status and base salary. Beginning in fiscal 2003, the Named Executive Officers were given a Flexible Perquisites Allowance to cover perquisites that may have been previously paid on behalf of each executive. Flex credits can be (a) used to purchase various benefits (such as extended health or dental coverage, disability insurance and life insurance) on the same terms as are available to all employees; (b) applied as contributions to the Stock Purchase and Savings Plan (as described in Note 3 below); or (c) paid to the employee as additional compensation. In 2005, Mr. Tutcher received perquisites and other personal benefits totaling $30,000, all of which related to his Flexible Perquisites Allowance; Mr. McGill received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Maki

received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Kaitson received perquisites and other personal benefits totaling $10,000, all of which related to his Flexible Perquisites Allowance, and Mr. Adams received perquisites and other personal benefits totaling $20,000 all of which related to his Flexible Perquisites Allowance.

(3) Employees in the United States participate in the Enbridge Employee Services, Inc. Savings Plan (the 401(k) Plan) under which employees may contribute up to 50% of their base salary, with employee contributions up to 5% matched by Enbridge (all subject to the contribution limits specified in the Internal Revenue Code). Enbridge s contributions are used to purchase Enbridge shares at market value and the employees contributions may be used to purchase Enbridge shares or nine designated funds. During 2005, Enbridge made contributions of $10,500, $10,500, $9,134.34, $9,875.06, and $8,571.53, respectively, to the 401(k) Plan for the benefit of Mr. Tutcher, Mr. McGill, Mr. Kaitson, Mr. Maki, and Mr. Adams. Mr. Tutcher also received $5,000 as reimbursement for professional financial services. Additionally, during 2005 Enbridge Employee Services, Inc. paid term life insurance premiums of $540, $529, $393, $413, and $378 for the benefit of Mr. Tutcher, Mr. McGill, Mr. Kaitson, Mr. Maki, and Mr. Adams, respectively. In 2005, Enbridge Employee Services, Inc. also furnished Messrs. Tutcher, McGill and Kaitson with parking benefits, at an annual cost of $1,857.

(4) Each option entitles the holder to acquire the indicated number of shares of Enbridge common stock. The costs associated with recognizing the fair value of the options as compensation expense are borne by the Partnership. Additional information is provided in the following section labeled Stock Options .

Stock Options

We do not maintain any compensation plans for the benefit of the Named Executive Officers under which equity interests in Enbridge Management or the Partnership may be awarded. In 2004, Enbridge began allocating to us the compensation expense it recognized in connection with recording the fair value of its outstanding stock options granted to certain of our officers, including the Named Executive Officers. Prior to 2004, we were not allocated any expense associated with stock option grants. The stock options are granted to the Named Executive Officers pursuant to the Enbridge Incentive Stock Option Plan, which is a long-term incentive plan administered by the Human Resources & Compensation Committee of Enbridge. The stock option grants are denominated in Canadian dollars. The following two tables set forth information concerning options granted and exercised during 2005 by the Named Executive Officers under the Enbridge stock option plans:

Options/SAR Grants in Last Fiscal Year

Name	Individual Grants Number of Securities Underlying Options/SARs Granted (#)	Percent of Total Options/SARs Granted to Employees in Fiscal Year	Exercise or Base Price ($CAD/Sh)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Options Term 5% $CAD	10% $CAD
D.C. Tutcher	34,000	2.22%	31.68	February 3, 2015	677,395	1,716,651
T.L. McGill	20,400	1.33%	31.68	February 3, 2015	406,437	1,029,991
E.C. Kaitson	11,600	0.76%	31.68	February 3, 2015	231,111	585,681
M.A. Maki	11,400	0.74%	31.68	February 3, 2015	227,127	575,583
R.L. Adams	10,800	0.70%	31.68	February 3, 2015	215,173	545,289

Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year End Option/SAR Values

Name	Shares Acquired on Exercise (#)	Value Realized ($CAD)	Number of Securities Underlying Unexercised Options/SARs At Fiscal Year-End(1) Exercisable (#)	Unexercisable (#)	Value of Unexercised In-The-Money Options/SARS At Fiscal Year-End Exercisable ($CAD)	Unexercisable ($CAD)
D.C. Tutcher			575,194	214,500	9,826,198	2,622,450
T.L. McGill	34,500	365,788	33,200	85,100	466,148	938,522
E.C. Kaitson			121,420	31,400	2,577,113	309,273
M.A. Maki			46,200	54,600	685,031	609,135
R.L. Adams	24,900	237,299		36,600		373,808

(1) The number of securities underlying unexercised options/SARs at May 20, 2005, were adjusted for a 2-for-1 stock split declared by Enbridge on its shares.

Enbridge also maintains a long-term, performance-based stock unit plan (the PSU Plan). Under the PSU Plan, participating executives receive annual grants of PSUs. The initial value of each of these PSUs is equivalent to the market value of one Enbridge share. Each award may be paid out at the end of a three-year performance cycle based on: 1) the market value of the Enbridge share at the end of the three-year period; 2) additional PSUs representing dividends paid during the three-year period; and 3) Enbridge s total shareholder return over a three-year period relative to a peer group of companies established in advance by Enbridge s Human Resources & Compensation Committee. Payments under the PSU Plan may be increased up to 200% of the original award when Enbridge outperforms its peer group. If performance fails to meet threshold performance levels, no payments are made. Enbridge does not issue any shares in connection with the PSU Plan. The compensation expense associated with recognizing the fair value of the outstanding stock units attributable to our executive officers that participate in the PSU Plan are allocated to us and expensed in our consolidated statements of income. The following table sets forth the grants made to the Named Executive Officers during 2005 pursuant to the PSU Plan:

Long-Term Incentive Plan Awards Table

Name	Securities, Units or Other Rights (#)	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Securities-Price-Based Plans Threshold(1) (#)	Target(2) (#)	Maximum(3) (#)
D.C. Tutcher	7,090	January 1, 2005-December 31, 2007	284	7,090	14,180
T.L. McGill	2,880	January 1, 2005-December 31, 2007	115	2,880	5,760
E.C. Kaitson		January 1, 2005-December 31, 2007			
M.A. Maki	2,140	January 1, 2005-December 31, 2007	86	2,140	4,280
R.L. Adams	2,020	January 1, 2005-December 31, 2007	81	2,020	4,040

(1) Threshold refers to the minimum amount payable for a certain level of performance under the PSU Plan.

(2) Target refers to the amount payable if the specified performance target is reached.

(3) Maximum refers to the maximum payout possible as specified under the PSU Plan.

Pension Plan

The following tables illustrate the benefits payable under the defined benefit component of Enbridge s trusteed non-contributory pension plans (the Plan), which apply to the Named Executive Officers of the

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Partnership. The tables illustrate the total annual pension entitlements assuming the eligibility requirements for an unreduced pension have been satisfied. Plan benefits that exceed maximum pension rules applicable to registered plan benefits are paid from the Enbridge supplemental pension plan. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

For service prior to January 1, 2000, the Plan provides a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 1.6 percent of the average of the participant s highest annual salary during three consecutive years out of the last ten years of credited service multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50 percent of the participant s Social Security benefit, prorated by years in which the participant has both credited service and Social Security coverage. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

For service after December 31, 1999, the Plan provides for senior management employees, including the Named Executive Officers, a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 2 percent of the sum of (i) the average of the participant s highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant s three highest annual performance bonus periods, represented in each period by 50 percent of the actual bonus paid, in respect of the last five years of credited services, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

Pension Plan Tables

Service Prior to January 1, 2000, before Social Security Offset

	Years of Credited Service					
Remuneration(1)	**10**	**15**	**20**	**25**	**30**	**35**
$200,000	$ 32,000	$ 48,000	$ 64,000	$ 80,000	$ 96,000	$ 112,000
250,000	40,000	60,000	80,000	100,000	120,000	140,000
300,000	48,000	72,000	96,000	120,000	144,000	168,000
350,000	56,000	84,000	112,000	140,000	168,000	196,000
400,000	64,000	96,000	128,000	160,000	192,000	224,000
450,000	72,000	108,000	144,000	180,000	216,000	252,000
500,000	80,000	120,000	160,000	200,000	240,000	280,000
550,000	88,000	132,000	176,000	220,000	264,000	308,000
600,000	96,000	144,000	192,000	240,000	288,000	336,000
650,000	104,000	156,000	208,000	260,000	312,000	364,000
700,000	112,000	168,000	224,000	280,000	336,000	392,000
750,000	120,000	180,000	240,000	300,000	360,000	420,000
800,000	128,000	192,000	256,000	320,000	384,000	448,000

Service After December 31, 1999

Remuneration(1)	**10**	**15**	**20**	**25**	**30**	**35**
$200,000	$ 40,000	$ 60,000	$ 80,000	$ 100,000	$ 120,000	$ 140,000
250,000	50,000	75,000	100,000	125,000	150,000	175,000
300,000	60,000	90,000	120,000	150,000	180,000	210,000
350,000	70,000	105,000	140,000	175,000	210,000	245,000
400,000	80,000	120,000	160,000	200,000	240,000	280,000
450,000	90,000	135,000	180,000	225,000	270,000	315,000
500,000	100,000	150,000	200,000	250,000	300,000	350,000
550,000	110,000	165,000	220,000	275,000	330,000	385,000
600,000	120,000	180,000	240,000	300,000	360,000	420,000
650,000	130,000	195,000	260,000	325,000	390,000	455,000
700,000	140,000	210,000	280,000	350,000	420,000	490,000
750,000	150,000	225,000	300,000	375,000	450,000	525,000
800,000	160,000	240,000	320,000	400,000	480,000	560,000

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(1) Remuneration refers to annual salary and that portion of the annual bonus eligible for inclusion in final average earnings.

Mr. Tutcher accumulates pension credits equal to 4.0 percent for each year of service to his tenth anniversary of employment with Enbridge.

For purposes of computing the total retirement benefit of the Named Executive Officers, the following table sets forth the service accrued prior to January 1, 2000, (Pre 2000 Service) and service accrued after December 31, 1999 (Post 1999 Service) by the Named Executive Officers at December 31, 2004. These figures include the additional service mentioned in the previous paragraph.

Name	**Age**	**Pre 2000 Service**	**Post 1999 Service**
D.C. Tutcher	56		4.58
T.L. McGill	51		3.83
E.C. Kaitson	49		4.58
M.A. Maki	41	13.32	6.00
R.L. Adams	41	14.70	4.50

Employment Agreements

Messrs. Tutcher and Kaitson have executive employment agreements with Enbridge. The agreements commenced on May 11, 2001, and continue until the earlier of (i) the date of voluntary retirement in accordance with the retirement policies established for senior employees of Enbridge (ii) the voluntary resignation which is not a constructive dismissal, or (iii) termination based on disability, death, cause or by either party. The agreements provide that in the event of termination of employment, the executive agrees to keep confidential all information of a confidential or proprietary nature and further agrees not to use such information for personal advantage. The agreements also provide for a base salary, annual reviews, discretionary raises, participation in short and long-term incentive plans of Enbridge, and severance payments in the amount of two years compensation in the event of termination by Enbridge.

Director Compensation

Enbridge employees who are members of the board of directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities.

During 2005, independent members of the board of directors of the General Partner and Enbridge Management received an aggregate annual fee of $30,000, paid quarterly, plus $1,000 per day for each meeting attended of the board of directors or committees of the board. In addition, each independent director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees and an additional $500 for meetings requiring out of state travel. The director who serves as chairman of the audit committees is paid an additional $7,500 per year and the director who serves as chairman of the boards is paid an additional $10,000 per year, paid quarterly.

As of January, 1, 2006, the Director Compensation Plan was amended to increase the annual retainer to $75,000 and additional meeting fees were eliminated. The retainers paid to directors serving as the chairman of the boards and chairman of the audit committees will remain at current levels. The out of state travel fee will be increased to $1,500. As part of this change to the Director Compensation Plan, the directors voted to amend the Corporate Governance Guidelines to incorporate an expectation that independent directors will hold a personal investment in either or both of Enbridge Energy Partners, L.P. or Enbridge Management, of at least two times the annual board retainer (i.e., 2 X $75,000 = $150,000). Directors would be expected to achieve the foregoing level of share ownership by the later of January 1, 2011 or five years from the date they became a director.

The General Partner indemnifies each director for actions associated with being a director to the full extent permitted under Delaware law and maintains errors and omissions insurance.

Messrs. Hambrook and Connelly served on a pricing committee in 2005 in connection with public offerings to sell limited partnership interest in the Partnership. As compensation for serving on the pricing committee, they each received a fee of $1,000 per meeting.

Messrs. Hambrook and Connelly and Ms. Hesse also served on a special committee during 2005 in connection with an evaluation of a proposed transaction with an Enbridge affiliate. As compensation for serving on the special committee, they each received a fee of $1,000 per meeting and Mr. Hambrook received $3,000 for serving as the chairman of that committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a) Security Ownership of Certain Beneficial Owners

The following table sets forth information as of February 15, 2006, with respect to persons known to us to be the beneficial owners of more than 5% of either class of the Partnership s Units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent Of Class
Enbridge Energy Management, L.L.C. 1100 Louisiana, Suite 3300 Houston, TX 77002	i-units	11,933,019	100.0
Enbridge Energy Company, Inc. 1100 Louisiana, Suite 3300 Houston, TX 77002	Class B Common Units	3,912,750	100.0

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(b) Security Ownership of Management and Directors

The following table sets forth information as of February 15, 2005, with respect to each class of our units beneficially owned by the Named Executive Officers, directors and nominees for director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

Name	Title of Class	Amount and Nature of Beneficial Ownership(1)	Percent Of Class
J.A. Connelly	Class A Common Units	5,000	*
P.D. Daniel	Class A Common Units		
E.C. Hambrook	Class A Common Units	2,000	*
M.O. Hesse	Class A Common Units		
G.K. Petty	Class A Common Units	1,000	*
D.C.Tutcher	Class A Common Units	20,200	*
J.R. Bird	Class A Common Units		
L.A. Zupan	Class A Common Units		
M.A. Maki	Class A Common Units		
T.L. McGill	Class A Common Units		
A.D. Meyer	Class A Common Units		
R.L. Adams	Class A Common Units		
D.V. Krenz	Class A Common Units		
V.D. Yu	Class A Common Units		
J.L. Balko	Class A Common Units		
E.C. Kaitson	Class A Common Units		
B.A. Stevenson	Class A Common Units		
All Officers, directors and nominees as a group 17 persons)	Class A Common Units	28,200	*

* Less than 1%

(1) Each beneficial owner has sole voting and investment power with respect to all the units attributed to him/her.

Item 13. Certain Relationships and Related Transactions

Interest of the General Partner in the Partnership

At December 31, 2005, the General Partner owned 3,912,750 Class B Common Units representing a 5.8% limited partner interest in the Partnership. In addition, the General Partner also owns 2,015,853 Listed shares or 17.2% of Enbridge Management s outstanding Listed shares, constituting an effective 3.0% limited partner interest in the Partnership. Together with the 2% general partner interest, the General Partner effectively owns a total of 10.8% of the Partnership and received $39.8 million in cash and incentive distributions.

Interest of Enbridge Management in the Partnership

At December 31, 2005, Enbridge Management owned 11,704,948 i-units, representing an 17.5% limited partner interest in us. The i-units are a separate class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management s limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management s limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

Cash Distributions

As discussed in Part II, Item 7 , we make quarterly cash distributions of all of our available cash to our General Partner and the holders of our common units. Under the Partnership Agreement, our General Partner receives incremental incentive cash distributions on the portion of cash distributions on a per unit basis that exceed certain target thresholds as follows:

	Unitholders	General Partner
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, incentive distributions paid to the General Partner were approximately $25.3 million.

Other Related Party Transactions

The Partnership, which has no employees, uses the services of Enbridge and its affiliates (the Group) for management, operating and administrative services of our business.

For further discussion of this and other related party transactions, refer to Note 10 Related Party Transactions in the Notes to the Consolidated Financial Statements beginning on Page F-2 of this Annual Report on Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, our principal independent auditors, for each of our last two fiscal years.

	For the years ended December 31,	
	2005	2004
Audit fees(1)	$ 2,276,166	$ 2,143,655
Audit related fees(2)		
Tax fees(3)	680,500	756,868
All other fees		
Total	$ 2,956,666	$ 2,900,523

(1) Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

(2) Audit related fees consist of fees billed for professional services rendered for Sarbanes-Oxley Section 404 consultation.

(3) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1 s.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance & Risk Committee of Enbridge Management s Board of Directors, or services up to $50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under Board of Directors delegated authority. All services in 2005 and 2004 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements, which are incorporated by reference in Item 8 are included beginning on page F-1.*

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2005, 2004, and 2003.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2005, 2004, and 2003.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004, and 2003.

e. Consolidated Statements of Financial Position as of December 31, 2005 and 2004.

f. Consolidated Statements of Partners Capital for the years ended December 31, 2005, 2004, and 2003.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the Consolidated Financial Statements or Notes thereto, or the required information is immaterial.

(3) *Exhibits.*

Reference is made to the Index of Exhibits following the signature page, which is hereby incorporated into this Item.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C., as delegate of the General Partner

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
(President)

Date: February 22, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 22, 2006 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ DAN C. TUTCHER		/s/ M.A. MAKI
Dan C. Tutcher President and Director (Principal Executive Officer)		M.A. Maki Vice President Finance (Principal Financial Officer)
/s/ J.A. CONNELLY		/s/ E.C. HAMBROOK
J.A. Connelly Director		E.C. Hambrook Director
/s/ G.K. PETTY		/s/ P.D. DANIEL
G.K. Petty Director		P.D. Daniel Director
/s/ M.O. HESSE		/s/ J.R. BIRD
M.O. Hesse Director		J.R. Bird Director

Index to Exhibits

Each exhibit identified below is filed as a part of this Annual report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

Exhibit Number	**Description**
3.1	Certificate of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership s Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (Exhibit 3.2 to the Partnership s 2000 Form 10-K/A dated October 9, 2001).
3.3	Third Amended and Restated Agreement of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
4.1	Form of Certificate representing Class A Common Units (Exhibit 4.1 to the Partnership s 2000 Form 10-K/A dated October 9, 2001).
10.1	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (Exhibit 10.10 to the Partnership s 1991 Form 10-K).
10.2	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (Exhibit 10.11 to the Partnership s 1991 Form 10-K).
10.3	Contribution Agreement (Exhibit 10.1 to the Partnership s Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	First Amendment to Contribution Agreement (Exhibit 10.8 to the Partnership s Registration Statement on Form S-3/A filed on September 24, 2002).
10.5	Second Amendment to Contribution Agreement (Exhibit 99.3 to the Partnership s Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (Exhibit 10.2 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
10.7	First Amending Agreement to the Delegation of Control Agreement dated as of February 21, 2005 (Exhibit 10.1 to the Partnership s Quarterly Report on Form 10-Q filed on May 5, 2005).
10.8	Amended and Restated Treasury Services Agreement (Exhibit 10.3 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
10.9	Operational Services Agreement (Exhibit 10.4 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
10.10	General and Administrative Services Agreement (Exhibit 10.5 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
10.11	Omnibus Agreement (Exhibit 10.6 to the Partnership s Quarterly Report on Form 10-Q filed on November 14, 2002).
10.12	Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.11 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.13	First Amendment, dated January 12, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.1 to the Partnership s Quarterly Report on Form 10-Q filed on May 4, 2004).

10.14	Second Amendment, dated April 26, 2004, to Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.2 to the Partnership s Quarterly Report on Form 10-Q filed on May 4, 2004).
10.15	Third Amendment to the Amended and Restated Credit Agreement, dated as of January 24, 2003 (as amended by the First Amendment, dated January 12, 2004 and the Second Amendment, dated as of April 26, 2004), by and the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K filed on April 19, 2005).
10.16	Fourth Amendment to the Amended and Restated Credit Agreement, dated January 24, 2003 (as amended by the First Amendment, dated January 12, 2004, the Second Amendment, dated April 26, 2004, and the Third Amendment dated April 14, 2005), by and among the Partnership, the lenders from time to time parties thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K filed on September 21, 2005).
10.17	Commercial Paper Dealer Agreement between the Company, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.1 to the Partnership s Current Report on Form 8-K filed May 3, 2005).
10.18	Commercial Paper Dealer Agreement between the Company, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.2 to the Partnership s Current Report on Form 8-K filed May 3, 2005).
10.19	Commercial Paper Dealer Agreement between the Company, as Issuer, and Goldman, Sachs & Co., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.3 to the Partnership s Current Report on Form 8-K filed May 3, 2005).
10.20	Commercial Paper Dealer Agreement between the Company, as Issuer, and Merrill Lynch Money Markets Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to exhibit 10.4 to the Partnership s Current Report on Form 8-K filed May 3, 2005).
10.21	Issuing and Paying Agency Agreement between the Company and Deutsche Bank Trust Company Americas, dated as of April 21, 2005 (incorporated by reference to exhibit 10.5 to the Partnership s Current Report on Form 8-K filed May 3, 2005).
10.22	Amended and Restated 364-Day Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.12 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.23	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.13 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.24	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.14 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.25	Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge (U.S.) Inc., as lender (Exhibit 10.15 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.26	Note Agreement and Mortgage, dated December 12, 1991 (Exhibit 10.1 to the Partnership s 1991 Form 10-K).

10.27	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (Exhibit 10.4 to the Partnership s 1992 Form 10-K).
10.28	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (Exhibit 10.17 to the Partnership s 1996 Form 10-K).
10.29	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project (Exhibit 10.21 to the Partnership s 1998 Form 10-K).
10.30	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender (Exhibit 10.19 to the Partnership s 1998 Form 10-K).
10.31	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (Exhibit 10.26 to the Partnership s 1999 Form 10-K).
10.32	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.1 to the Lakehead Pipe Line Company, Limited Partnership s Current Report on Form 8-K dated October 20, 1998).
10.33	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership s Current Report on Form 8-K dated October 20, 1998).
10.34	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.3 to the Lakehead Pipe Line Company, Limited Partnership s Current Report on Form 8-K dated October 20, 1998).
10.35	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership s Current Report on Form 8-K dated November 16, 2000).
10.36	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.4 to the Lakehead Pipe Line Company, Limited Partnership s Current Report on Form 8-K dated October 20, 1998).
10.37+	Executive Employment Agreement, dated May 11, 2001, between Dan C. Tutcher, as Executive, and Enbridge Inc., as Corporation (Exhibit 10.26 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.38+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (Exhibit 10.27 to the Partnership s Annual Report on Form 10-K filed on March 28, 2003).
10.39	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (Exhibit 4.5 to the Partnership s Registration Statement on Form S-4 filed on June 30, 2003).
10.40	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership s Registration Statement on Form S-4 filed on June 30, 2003).
10.41	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership s Registration Statement on Form S-4 filed on June 30, 2003).

10.42	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (Exhibit 99.3 to the Partnership s Current Report on Form 8-K filed on January 9, 2004).
10.43	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (Exhibit 4.2 to the Partnership s Current Report on Form 8-K filed on December 3, 2004).
10.44	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (Exhibit 4.3 to the Partnership s Current Report on Form 8-K filed on December 3, 2004).
10.45	Common Unit Purchase Agreement (Exhibit 1.1 to the Partnership s Current Report on Form 8-K filed on February 10, 2004.
10.46	Common Unit Purchase Agreement (Exhibit 1.1 to the Partnership s Current Report on Form 8-K filed on February 10, 2005.
10.47	Common Unit Purchase Agreement (Exhibit 1.1 to the Partnership s Current Report on Form 8-K filed on November 17, 2005.
14.1	Code of Ethics for Senior Financial Officers (Exhibit 14.1 to the Partnership s Annual Report on Form 10-K filed on March 12, 2004).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of PricewaterhouseCoopers LLP.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (Exhibit 99.1 to the Partnership s Annual Report on Form 10-K filed February 25, 2005).

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, Texas 77002.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS,
SUPPLEMENTARY INFORMATION AND
CONSOLIDATED FINANCIAL STATEMENT SCHEDULES
ENBRIDGE ENERGY PARTNERS, L.P.

Financial Statements

FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this Report have been omitted because they are not applicable or the required information is either immaterial or shown in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners of
Enbridge Energy Partners, L.P.:

We have completed integrated audits of Enbridge Energy Partners, L.P. s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Partnership maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Partnership s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas

February 22, 2006

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ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	2005	**2004**	**2003**
	(dollars and units in millions, except per unit amounts)		
Operating revenue	$ 6,476.9	$ 4,291.7	$ 3,172.3
Operating expenses			
Cost of natural gas (Note 15)	5,763.3	3,587.1	2,612.7
Operating and administrative	326.8	274.1	211.8
Power	74.8	72.8	56.1
Depreciation and amortization (Note 6)	138.2	120.5	97.4
Gain on sale of assets	(18.1)		
	6,285.0	4,054.5	2,978.0
Operating income	191.9	237.2	194.3
Interest expense	(107.7)	(88.4)	(85.0)
Rate refunds (Note 13)		(13.6)	
Other income	5.0	3.0	2.4
Net income	$ 89.2	$ 138.2	$ 111.7
Net income allocable to common and i-units	$ 65.7	$ 115.7	$ 92.1
Net income per common and i-unit (basic and diluted) (Note 4)	$ 1.06	$ 2.06	$ 1.93
Weighted average units outstanding	62.1	56.1	47.7
Cash distributions paid per unit	$ 3.70	$ 3.70	$ 3.70

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

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ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Net income	$ 89.2	$ 138.2	$ 111.7
Other comprehensive loss (Notes 14 & 15)	(181.3)	(56.8)	(47.7)
Comprehensive (loss) income	$ (92.1)	$ 81.4	$ 64.0

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Cash provided by operating activities			
Net income	$ 89.2	$ 138.2	$ 111.7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 6)	138.2	120.5	97.4
Derivative fair value loss (Note 15)	58.4	3.2	0.3
Environmental liabilities (Note 12)		(2.0)	
Gain on sale of asset (Note 3)	(18.1)		
Other	(0.3)	0.4	(0.7)
Changes in operating assets and liabilities, net of cash acquired:			
Receivables, trade and other	(38.0)	(25.4)	(21.0)
Due from General Partner and affiliates	(12.4)	(0.5)	(7.2)
Accrued receivables	(237.1)	(128.5)	(59.2)
Inventory	(57.5)	(60.8)	(10.2)
Current and long-term other assets	(2.2)	15.3	(14.6)
Due to General Partner and affiliates	2.6	8.1	(8.7)
Accounts payable and other	41.7	36.8	(34.1)
Accrued purchases	295.3	120.8	76.6
Interest payable	8.8	14.5	15.9
Property and other taxes payable	(1.5)	4.8	2.0
Net cash provided by operating activities	267.1	245.4	148.2
Cash used in investing activities			
Additions to property, plant and equipment	(344.8)	(288.8)	(129.3)
Changes in construction payables	2.8	10.0	(7.5)
Asset acquisitions, net of cash acquired (Note 3)	(186.4)	(141.0)	(294.2)
Proceeds from sale of assets (Note 3)	105.4		
Settlement of natural gas collars (Note 3 and 15)	(16.3)		
Other	2.2	0.7	
Net cash used in investing activities	(437.1)	(419.1)	(431.0)
Cash provided by financing activities			
Proceeds from unit issuances, net (Note 10)	268.6	194.2	414.4
Distributions to partners (Note 10)	(210.6)	(191.0)	(156.7)
Repayments of credit facilities, net	(175.0)	(280.0)	(9.0)
Net issuances of commercial paper	330.0		
Proceeds from issuance of senior notes, net of issue costs		495.4	396.3
Repayments to the General Partner and affiliates			(327.1)
Repayments of First Mortgage Notes	(31.0)	(31.0)	(31.0)
Other	(0.5)		
Net cash provided by financing activities	181.5	187.6	286.9
Net increase in cash and cash equivalents	11.5	13.9	4.1
Cash and cash equivalents at beginning of year	78.3	64.4	60.3
Cash and cash equivalents at end of year	$ 89.8	$ 78.3	$ 64.4

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31,	
	2005	2004
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 2)	$ 89.8	$ 78.3
Receivables, trade and other, net of allowance for doubtful accounts of $4.5 in 2005 and $4.0 in 2004	109.7	71.7
Due from General Partner and affiliates	20.1	7.7
Accrued receivables	615.3	378.2
Inventory (Note 5)	138.9	84.5
Other current assets	11.5	13.4
	985.3	633.8
Property, plant and equipment, net (Note 6)	3,080.0	2,778.0
Other assets, net (Note 15)	22.2	27.7
Goodwill (Note 7)	258.2	257.2
Intangibles, net (Note 8)	82.7	74.0
	$ 4,428.4	$ 3,770.7
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 12.5	$ 9.9
Accounts payable and other (Note 15)	247.9	136.4
Accrued purchases	646.7	351.4
Interest payable	11.4	12.3
Property and other taxes payable	21.8	23.3
Current maturities of long-term debt (Note 9)	31.0	31.0
	971.3	564.3
Long-term debt (Note 9)	1,682.9	1,559.4
Loans from General Partner and affiliates (Note 11)	151.8	142.1
Environmental liabilities (Note 12)	4.8	5.3
Other long-term liabilities (Note 15)	253.8	101.7
	3,064.6	2,372.8
Commitments and contingencies (Note 13)		
Partners capital (Note 10)		
Class A common units (Units issued 49,938,834 in 2005 and 44,296,134 in 2004)	1,142.4	1,021.6
Class B common units (Units issued 3,912,750 in 2005 and 2004)	67.2	66.7
i-units (Units issued 11,704,948 in 2005 and 10,902,409 in 2004)	421.7	399.4
General Partner	34.6	31.0
Accumulated other comprehensive loss (Note 14 & 15)	(302.1)	(120.8)
	1,363.8	1,397.9
	$ 4,428.4	$ 3,770.7

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	Year ended December 31, 2005 Units	Amount	2004 Units	Amount	2003 Units	Amount
	(dollars in millions)					
Class A common units:						
Beginning balance	44,296,134	$ 1,021.6	40,166,134	$ 914.9	31,313,634	$ 604.8
Net income allocation		48.9		85.4		64.9
Allocation of proceeds and issuance costs from unit issuance	5,642,700	242.7	4,130,000	175.0	8,852,500	368.2
Distributions		(170.8)		(153.7)		(123.0)
Ending balance	49,938,834	1,142.4	44,296,134	1,021.6	40,166,134	914.9
Class B common units:						
Beginning balance	3,912,750	66.7	3,912,750	64.2	3,912,750	48.7
Net income allocation		4.8		8.7		8.3
Allocation of proceeds and issuance costs from unit issuance		10.2		8.2		21.7
Distributions		(14.5)		(14.4)		(14.5)
Ending balance	3,912,750	67.2	3,912,750	66.7	3,912,750	64.2
i-units:						
Beginning balance	10,902,409	399.4	10,062,170	370.7	9,228,655	335.6
Net income allocation		12.0		21.6		18.9
Allocation of proceeds and issuance costs from unit issuance		10.3		7.1		16.2
Distributions	802,539		840,239		833,515	
Ending balance	11,704,948	421.7	10,902,409	399.4	10,062,170	370.7
General Partner:						
Beginning balance		31.0		27.5		18.8
Net income allocation		23.5		22.5		19.6
Allocation of proceeds and issuance costs from unit issuance		(0.3)		(0.2)		(0.3)
General Partner contribution		5.7		4.1		8.6
Distributions		(25.3)		(22.9)		(19.2)
Ending balance		34.6		31.0		27.5
Accumulated other comprehensive loss:						
Beginning balance		(120.8)		(64.0)		(16.3)
Unrealized loss on derivative financial instruments		(181.3)		(56.8)		(47.7)
Ending balance		(302.1)		(120.8)		(64.0)
Partners capital at December 31,		$ 1,363.8		$ 1,397.9		$ 1,313.3

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

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ENBRIDGE ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P. and its consolidated subsidiaries, referred to herein as we, us, our, and the Partnership, is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. Our Class A Common Units are traded on the New York Stock Exchange (NYSE) under the symbol EEP.

We were formed in 1991 by Enbridge Energy Company, Inc. (our General Partner), which is an indirect, wholly-owned subsidiary of Enbridge Inc. (Enbridge) of Calgary, Alberta. We were formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership (the Lakehead Partnership) which owns the United States portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the Unites States to eastern Canada.

For several years, we have been diversifying geographically and operationally through acquisitions of crude oil gathering, transportation and storage assets, and of natural gas gathering, treating, processing, marketing and transportation systems in the Gulf Coast and mid-continent regions of the United States. We hold our assets in a series of limited liability companies and limited partnerships that we own directly or indirectly.

Our ownership at December 31, 2005 and 2004 is comprised of the following:

		2005		2004	
Class A common units owned by the public		74.7	%	73.4	%
Class B common units owned by our General Partner		5.8	%	6.5	%
i-units owned by Enbridge Management		17.5	%	18.1	%
General Partner interest		2.0	%	2.0	%
		100.0	%	100.0	%

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C. and its subsidiary, which we refer to as Enbridge Management, is a Delaware limited liability company, formed in May 2002. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management s Listed Shares are traded on the NYSE under the symbol EEQ. Enbridge Management owns all of a special class of our limited partner interests, referred to as i-units and receives its earnings from this investment.

Enbridge Management s principal activity is managing and controlling our business and affairs pursuant to a delegation of control agreement with our general partner. The Delegation of Control Agreement provides that Enbridge Management will not amend or propose to amend our partnership agreement, allow a merger or consolidation involving us, allow a sale or exchange of all or substantially all of our assets or dissolve or liquidate us without the approval of our general partner. In accordance with its limited liability company agreement, Enbridge Management s activities are restricted to being our limited partner and managing our business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of our general partner and is publicly traded on the NYSE and Toronto Stock Exchange under the symbol ENB. Enbridge is a leader in the transportation and distribution of energy, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution in North America. Enbridge also has international interests located in Western Europe and Latin America. At December 31, 2005 and 2004, Enbridge and its consolidated subsidiaries owned an effective 10.8% and 11.6% interest in us through its ownership in Enbridge Management and our general partner.

Business Segments

We conduct our business through three segments: Liquids, Natural Gas, and Marketing.

Liquids

Our Liquids segment includes the Lakehead, North Dakota, and the Mid-Continent systems. Our Lakehead system consists of an interstate common carrier crude oil and liquid petroleum pipeline that is regulated by the Federal Energy Regulatory Commission, or FERC, and storage assets, all of which are located in the Great Lakes and Midwest regions of the United States. Our Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline in the world. The Lakehead system, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Our North Dakota system includes approximately 330 miles of crude oil gathering lines connected to an interstate transportation line that is approximately 620 miles long and is regulated by the FERC. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. Our Mid-Continent system consists of over 480 miles of crude oil pipelines including the FERC-regulated Ozark pipeline and approximately 11.9 million barrels of storage capacity, which serves refineries in the U.S. Mid-Continent region from Cushing, Oklahoma.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, treating and processing plants and related facilities. Our Natural Gas segment includes eight natural gas treating plants and 15 natural gas processing plants at December 31, 2005, excluding plants that are inactive. In addition, our Natural Gas segment includes approximately 11,000 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids (NGL or NGLs), crude oil and carbon dioxide.

Our Natural Gas segment also includes four FERC regulated natural gas transmission pipeline systems located in the mid-continent and Gulf Coast regions of the United States.

Marketing

Our Marketing segment primarily provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines as well as other interconnected natural gas pipeline systems. We primarily undertake marketing activities to increase the utilization of our natural gas pipelines, realize incremental margin on gas purchased at the wellhead, and provide value-added services to customers.

Our Marketing business purchases third-party pipeline transportation capacity which provides our customers with access to natural gas markets that might not be directly accessible from our existing natural gas pipelines. Our Marketing business also purchases third-party storage capacity which permits us to inject and store natural gas over various periods of time for withdrawal as these products become needed by end users of natural gas. These contracts may be denoted as firm transportation, interruptible transportation, firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with our natural gas purchase and sale contracts and to provide us with opportunities to competitively market the natural gas and NGL products.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. We regularly evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Partnership and its wholly-owned subsidiaries on a consolidated basis. All significant intercompany items have been eliminated in consolidation.

Regulation

Certain of our liquids and natural gas activities are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers.

Certain of the natural gas systems are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded for non-regulated entities under US GAAP.

Revenue Recognition and the Use of Estimates for Revenues and Cost of Natural Gas

Liquids

Revenues of our Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and contract storage revenues related to the Partnership s tankage assets. The tariffs specify the amounts to be paid by shippers for service between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. Revenues are recognized upon delivery to customers of products, as pricing is determinable and collectibility is reasonably assured. The contract storage revenues are recognized based on contractual terms under which customers pay for the option of availability of storage capacity and /or a fee based on through-put volumes. Revenues are recognized as storage services are rendered, pricing is determinable and collectibility is reasonably assured. In the Liquids segment, we generally do not own the crude oil and liquid petroleum that we transports or store, and therefore, we do not assume significant direct commodity risk.

Natural Gas

We recognize revenue upon delivery of natural gas and NGLs to customers, and/or when services are rendered, pricing is determinable and collectibility is reasonably assured. We derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based Arrangements:

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services provided and do not depend directly on commodity prices. Revenues of the Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of the FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. Revenues are recognized as natural gas is delivered to customers or as transportation services are rendered, pricing is determinable and collectibility is reasonably assured.

Other Arrangements:

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Please refer to Note 15 for more information about our derivative activities.

These other types of arrangements are categorized as follows:

- Percentage-of-Index-Contracts Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Percentage-of-Proceeds Contracts Under the terms of these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.

- Percentage-of-Liquids Contracts Under these contracts, we receive a negotiated percentage of NGLs and condensate from natural gas that requires processing. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGL and condensate.

- Keep-Whole Contracts Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account the residue gas resulting from processing at market prices. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with a British thermal unit content equivalent to the original raw gas we received.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our unitholders from volatility in our cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the

processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

Marketing

Revenues of our Marketing segment are derived from providing supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Natural gas marketing activities are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. In general, natural gas purchased and sold by our Marketing business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, we will enter into long-term fixed price purchase or sales contracts with our customers and usually will enter into offsetting positions under the same or similar terms. Revenues are recognized upon delivery of natural gas and NGLs to customers and/or when services are rendered, pricing is determinable and collectibility is reasonably assured.

Use of Estimates

For our natural gas businesses, we must estimate our current month revenue and cost of gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month s estimate to equal the prior month s actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each of the years ended December 31, 2005, 2004 and 2003. We believe that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of our processes.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

We extinguish liabilities when a creditor has relieved us of the obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. As such, included in Accounts Payable and Other are obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $46.5 million and $25.3 million at December 31, 2005 and 2004, respectively.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. All inventories are valued at the lower of cost or market. The product inventory consists of liquids and natural gas. Upon disposition, product inventory is recorded to Cost of natural gas at the weighted average cost of inventory.

Materials and supplies inventory is either used during operations and expensed to operating expenses, or used on capital projects and/or new construction, and capitalized to property, plant and equipment.

Oil Measurement Losses

Oil measurement losses occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are a function of crude oil prices and the level of the carrier s inventory.

There are inherent difficulties in quantifying oil measurement losses because physical measurements of volumes are not practical, as products continuously move through our pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement losses is especially difficult for us because of the length of the pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses. If there is a material change in these assumptions, it may result in a revision of oil measurement loss estimates in the period determined.

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in kind through the receipt or delivery of natural gas in the future. Gas imbalances are recorded as current assets or current liabilities on the balance sheet using the posted index prices, which approximate market rates, or our weighted average cost of gas.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced or improved; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include first-time high resolution integrity tool runs, the costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of the pipeline system following an integrity tool run and natural gas or crude oil well-connects, and mainline systems expansions.

Recent regulatory guidance issued by the FERC will require us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation s Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We are adopting this guidance prospectively for our SFAS No. 71 companies only, namely, our UTOS, Midla, AlaTenn and KPC natural gas transmission systems. Consistent with our prior practice, costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition will continue to be capitalized for our FERC-regulated and non-regulated pipeline systems. Additionally, for our non-regulated pipelines and our FERC-regulated crude oil pipelines that are not eligible to apply the provisions of SFAS No. 71, we will continue to capitalize first-time in-line inspection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects, consistent with our historical policy. For regulatory reporting, our FERC-regulated crude oil pipelines will expense items 1-4 listed above. We do not expect our implementation of this regulation to significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost and depreciate our assets over the lesser of their estimated useful lives or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a processing plant, treating facility or a pipeline system are sold, we will recognize a gain or loss in our Consolidated Statements of Income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Income.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is allocated to two of our segments, Natural Gas and Marketing.

Goodwill is not amortized, but is tested for impairment annually based on carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent five-year plan, which we use to manage the business. There have been no impairments recorded in 2005, 2004 or 2003.

Intangibles, Net

Intangibles, net, consist of natural gas purchase and sale customer contracts and natural gas supply opportunities, which we amortize on a straight-line basis over the weighted average useful life of the underlying assets, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. We did not record any impairments in 2005, 2004, or 2003.

Other Assets

Other assets primarily include deferred financing charges, which are amortized on a straight-line basis, over the life of the related debt and classified as interest expense on the Consolidated Statements of Income.

Income Taxes

We are not a taxable entity for federal and state income tax purposes. Accordingly, no recognition is given to income taxes for financial reporting purposes. The tax on our net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner s tax attributes in us is not available.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in market prices such as interest rates, natural gas prices, natural gas liquids prices and processing spreads. In order to manage the risks to unitholders, we use a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133) all derivative financial instruments are recorded in the balance sheet at their fair value. We record the fair value of our derivative financial instruments in the balance sheet as current and long-term assets or liabilities on a net basis by counterparty. For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument s intended use and how it is designated. For our derivative financial instruments related to commodities that do not qualify for hedge accounting, the change in market value is recorded as a component of Cost of natural gas in the Consolidated Statements of Income. For our derivative financial instruments related to interest rates that do not qualify for hedge accounting, the change in market value is recorded as a component of interest expense in the Consolidated Statements of Income.

In implementing our hedging programs, we have established a formal analysis, execution and reporting framework that requires the approval of the Board of Directors of Enbridge Management or a committee of our senior management. We employ derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment and in use by the Partnership can generally be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. We enter into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. We enter into fair value hedges to hedge the value of a recognized asset or liability.

Price assumptions we use to value the cash flow and fair value hedges can affect net income for each period. We use published market price information where available, or quotations from over-the-counter (OTC) market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts reported in our consolidated financial statements change quarterly as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or the fair value of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are determined to be highly effective, are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge s change in value is recognized immediately in earnings. For fair value hedges, the change in value of the financial instrument is determined each period and is taken into earnings. In conjunction with this, the change in the value of the hedged item is also calculated and taken into earnings. To the extent that the two valuations offset, the hedge is effective and net earnings is not affected.

Our earnings are also affected by the use of the mark-to-market method of accounting required under GAAP for certain basis swap financial instruments. Short-term, highly liquid financial instruments such as basis swaps and other contracts are used to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within the Marketing segment. As of December 31, 2005, these basis swap financial instruments, however, did not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the mark-to-market method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments may cause non-cash earnings to fluctuate based upon changes in the underlying indices, primarily commodity prices. The fair value of these financial instruments is determined using price data from highly liquid markets such as the New York Mercantile Exchange or NYMEX or OTC market makers or other similar sources.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. Amounts for remediation of existing environmental contamination caused by past operations, which do not benefit future periods by preventing or eliminating future contamination, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by government organizations. These estimates are subject to revision in future periods based on actual costs or new information and are included on the balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss.

Asset Retirement Obligations

We adopted the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143) in January 2003. The provisions of SFAS No. 143 require us to record a liability for the fair value of asset retirement obligations, on a discounted basis, in the period in which the liability is incurred, which is typically at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. The provisions also require that we capitalize the costs associated with the asset retirement obligations as part of the carrying cost of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the retirement obligation due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for asset retirement obligations when assets are taken out of service or otherwise abandoned.

In December 2005, we adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* (FIN 47). FIN 47 requires us to recognize a liability and related asset, consistent with SFAS No. 143, for the fair value of conditional asset retirement obligations that we can reasonably estimate. FIN 47 also provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. As indicated in the table below, our implementation of FIN 47 did not have a material effect on our consolidated financial statements.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate an abandonment retirement obligation cost. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management s intent, or the asset s estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumer/refinery consumption. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

We recorded an asset and liability of $2.1 million for asset retirement obligations for the year ended December 31, 2005 in the Consolidated Statement of Financial Position. We recorded accretion expense of $0.5 million, $0.1 million and $0.1 million, respectively, in the Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003 for previously recorded asset retirement obligation liabilities.

No assets are legally restricted for purposes of settling our asset retirement obligations for each of the years ended December 31, 2005 and 2004. Following is a reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligation liabilities for each of the years ended December 31, 2005 and 2004:

	2005	**2004**
	(in millions)	
Balance at beginning of period	$ 1.0	$ 0.9
Implementation of FIN 47 Liability	2.1	
Accretion expense	0.5	0.1
Balance at end of period	$ 3.6	$ 1.0

Comparative Amounts

We have made reclassifications to the prior years reported amounts to conform to our presentation in the 2005 consolidated financial statements. These reclassifications were made within the Consolidated Statements of Financial Position, Consolidated Statements of Cash Flows, and Segment Information (note 16), and have no effect on net income.

New Accounting Pronouncements

Accounting Changes and Error Corrections

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3*. Under this statement, voluntary changes in accounting principle are required to be applied retrospectively for the direct effects of a change to prior periods financial statements, unless such application is impracticable. Retrospective application refers to reflecting a change in accounting principle in the financial statements of prior periods as if the principle had always been used. When retrospective application is determined to be impracticable, this statement requires the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective treatment is practicable with a corresponding adjustment to the opening balance of retained earnings. This statement retains the guidance in APB Opinion No. 20 for reporting the corrections of errors and changes in accounting estimates. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005, with early adoption permitted. Our adoption of this statement will affect our consolidated financial statements for any changes in accounting principle we may make in the future, and new pronouncements we adopt that do not provide transition provisions.

FERC Guidance on Accounting for Integrity Management Costs

In June 2005, the FERC issued guidance describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation s Office of Pipeline Safety. Under the guidance, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial and mitigation actions to correct an identified condition can be capitalized. The guidance is effective January 1, 2006, and will be applied prospectively to our SFAS No. 71 entities.

3. ACQUISITIONS AND DISPOSITIONS

We accounted for each of our completed acquisitions using the purchase method and record the assets acquired and liabilities assumed at their estimated fair market values as of the date of purchase. The results of operations from each of these acquisitions are included in earnings from the date of the acquisition.

2005 Acquisitions and Dispositions

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets in north Texas for $164.6 million in cash, including transaction costs of $0.5 million. The assets we acquired serve the Fort Worth Basin, which is mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines; and
- four processing plants with aggregate processing capacity of 121 million cubic feet of natural gas per day (MMcf/d).

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the natural gas and then selling the natural gas liquids and residue natural gas streams. The assets and results of operations are included in our Natural Gas segment from the date of acquisition.

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The purchase price and the allocation to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:	
Cash paid, including transaction costs	$ 164.6
Allocation of purchase price:	
Property, plant and equipment, including construction in progress	151.6
Intangibles, including contracts	14.3
Current liabilities	(0.9)
Contingent liabilities	(0.4)
Total	$ 164.6

Other 2005 Acquisitions

In June 2005, we acquired for $20.1 million in cash, a natural gas pipeline and related facilities consisting of 92 miles of 20-inch diameter pipeline that extends from Pampa, Texas into western Oklahoma and has interconnects with our Anadarko system. We integrated this pipeline into our existing Anadarko system and have included the assets and operating results in our Natural Gas segment from the date of acquisition. The purchase price for this acquisition was allocated to property, plant and equipment for $19.1 million and goodwill for $1.0 million. We also acquired other gathering and processing assets during 2005 that are complementary to our existing natural gas systems for cash totaling approximately $1.7 million.

Sale of Gathering and Processing Assets

In December 2005, we sold for $105.4 million in cash, a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million and recognized a gain on the sale of approximately $18.1 million. The facilities we sold represent non-strategic assets within our Natural Gas segment. In connection with this sale, we paid approximately $16.3 million to settle natural gas collars on 2,000 MMBtu/d associated with the natural gas produced by these assets and entered into offsetting derivatives at market to close out derivatives previously classified as hedges of 273 Bbl/d of NGL produced by these assets. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Refer to Note 15 for additional discussion regarding derivative transactions. The reported amounts are subject to change pending final settlement of the sale.

2004 Acquisitions

Mid-Continent System

In March 2004, we acquired crude oil pipeline and storage assets, known as the Mid-Continent system, for $117.0 million, including transaction costs of $2.0 million. The assets acquired serve refineries in the U.S. Mid-Continent from Cushing, Oklahoma and include:

- The 433-mile Ozark pipeline from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal located in El Dorado, Kansas;
- The 47-mile West Tulsa pipeline in Oklahoma; and
- A storage terminal at Cushing, with 8.3 million barrels of storage capacity.

These systems were acquired to provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated assets. The assets and results of operations are included in our Liquids segment from the date of acquisition. The value allocated to the assets was determined by an independent appraisal.

The purchase price and the allocation to assets acquired and liabilities assumed was as follows:

	(dollars in millions)
Purchase Price:	
Cash paid, including transaction costs	$ 117.0
Allocation of purchase price:	
Property, plant and equipment	$ 117.5
Current assets	0.2
Current liabilities	(0.2)
Environmental liabilities	(0.5)
Total	$ 117.0

Other 2004 Acquisitions

During 2004, we completed five separate acquisitions of natural gas assets for a total of $10.9 million. The purchase price for these acquisitions was applied to property, plant, and equipment and there was no goodwill recorded. The results of operations for the acquisitions are included in our Natural Gas segment from the date of acquisition.

In March 2004, we also purchased natural gas transmission and gathering pipeline assets for $13.1 million. The assets, referred to as the Palo Duro system, are located in Texas between our existing Anadarko and North Texas systems, and are expected to increase natural gas delivery flexibility to our customers. The assets purchased include approximately 400 miles of natural gas transmission and gathering pipelines, together with 5,200 horsepower of compression. The purchase price for this acquisition was applied to property, plant and equipment and no goodwill was recorded. The Palo Duro system s results of operations are included in our Natural Gas segment from the date of acquisition.

2003 Acquisitions

North Texas System

On December 31, 2003, we acquired natural gas gathering and processing assets in north Texas. The gathering system, referred to as the North Texas system, primarily serves the Fort Worth Basin, including the Barnett Shale producing zone, and is complementary to our existing natural gas systems in the area. The assets were purchased for cash of $249.6 million, which includes the buyout of a capital lease of $1.9 million and transaction costs of $1.7 million. The purchase was funded with borrowings under our credit facilities. The value allocated to the assets was determined by an independent appraisal. Goodwill associated with the acquisition was $23.8 million, and is allocated entirely to our Natural Gas segment. Intangible assets acquired of $48.1 million represent the fair value associated with the natural gas supply opportunities present in the Barnett Shale producing zone that will be shipped through the North Texas system and is recorded in our Natural Gas segment. Of the $2.7 million of environmental liabilities assumed, $0.5 million are included in Accounts payable and other and $2.2 million are included in environmental liabilities on our Consolidated Statement of Financial Position as of December 31, 2003.

The purchase price and the allocation to assets acquired and liabilities assumed was as follows:

	(dollars in millions)
Purchase Price:	
Cash paid, including transaction costs	$ 249.6
Allocation of purchase price:	
Current assets	$ 0.4
Property, plant and equipment, including construction in progress	181.0
Intangibles	48.1
Goodwill	23.8
Current liabilities	(1.0)
Environmental liabilities	(2.7)
Total	$ 249.6

Other 2003 Acquisition Transactions

In December 2003, we paid $43.8 million, which includes $2.0 million of interest, in full settlement of post-closing adjustments from the acquisition of acquired assets in 2002. The purchase price was therefore reduced by $8.8 million, which is reflected as a decrease to Goodwill in 2003.

4. NET INCOME PER COMMON AND i-UNIT

Net income per common and i-unit is computed by dividing net income, after deducting the General Partner s allocation, by the weighted average number of Class A and B common units and i-units outstanding. The General Partner s allocation is equal to an amount based upon its 2% general partner interest, adjusted to reflect an amount equal to incentive distributions earned and an amount required to reflect depreciation on the General Partner s historical cost basis for assets contributed on formation of the Partnership. As there are no dilutive securities outstanding, basic and diluted earnings per unit amounts are equal. Net income per common and i-unit was determined as follows:

	Year ended December 31,		
	2005	2004	2003
	(dollars and units in millions, except per unit amounts)		
Net income	$ 89.2	$ 138.2	$ 111.7
Allocations to the General Partner:			
Net income allocated to General Partner	(1.8)	(2.8)	(2.2)
Incentive distributions earned	(21.6)	(19.6)	(17.2)
Historical cost depreciation adjustments	(0.1)	(0.1)	(0.2)
	(23.5)	(22.5)	(19.6)
Net income allocable to common units and i-units	$ 65.7	$ 115.7	$ 92.1
Weighted average units outstanding	62.1	56.1	47.7
Net income per common and i-unit (basic and diluted)	$ 1.06	$ 2.06	$ 1.93

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5. INVENTORY

Inventory is comprised of the following:

	December 31, 2005	December 31, 2004
	(dollars in millions)	
Material and supplies	$ 8.3	$ 7.1
Liquids inventory	11.1	5.7
Natural gas inventory	119.5	71.7
	$ 138.9	$ 84.5

6. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	Depreciation Rates	December 31, 2005	December 31, 2004
	(dollars in millions)		
Land		$ 13.8	$ 14.4
Rights-of-way	0.6%-6.4 %	280.2	238.2
Pipeline	0.6%-6.7 %	2,194.2	1,919.8
Pumping equipment, buildings and tanks	1.6%-14.3 %	673.0	613.0
Compressors, meters, and other operating equipment	1.6%-20.0 %	310.0	227.8
Vehicles, office furniture and equipment	0.8%-33.3 %	102.7	80.0
Processing and treating plants	2.7%-4.0 %	79.0	95.6
Construction in progress		209.1	253.0
		3,862.0	3,441.8
Accumulated depreciation		(782.0)	(663.8)
		$ 3,080.0	$ 2,778.0

Based on a third-party study commissioned by management, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. Depreciation expense for the year ended December 31, 2005 was approximately $2.5 million lower as a result of the new depreciation rates.

7. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2005 and 2004 are as follows:

	Liquids	Natural Gas	Marketing	Corporate	Total
	(in millions)				
Balance as of December 31, 2003	$	$ 236.9	$ 20.4	$	$ 257.3
Purchase price adjustments		(0.1)			(0.1)
Balance as of December 31, 2004		236.8	20.4		257.2
Acquisition		1.0			1.0
Balance as of December 31, 2005	$	$ 237.8	$ 20.4	$	$ 258.2

In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets,* we completed our annual goodwill impairment test using data at June 30, 2005. To estimate the fair value of our reporting units we made estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures, and net working capital based on assumptions that are consistent with the long-range plans used to manage the business. Based on the results of the impairment analysis, the fair value of each reporting unit was determined to exceed the respective carrying amount, including goodwill. As a result, no goodwill impairment existed in any of our reporting units at June 30, 2005 and no events have occurred or circumstances changed that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2005.

8. INTANGIBLES

	December 31,					
	2005			2004		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
	(in millions)					
Customer contracts	$ 43.2	$ (4.7)	$ 38.5	$ 31.1	$ (3.3)	$ 27.8
Natural gas supply opportunities	48.1	(3.9)	44.2	48.1	(1.9)	46.2
	$ 91.3	$ (8.6)	$ 82.7	$ 79.2	$ (5.2)	$ 74.0

Customer contracts are comprised entirely of natural gas purchase and sale contracts and are recorded in our Natural Gas and Marketing segments. Customer contracts are amortized on a straight-line basis over the weighted average useful life of the underlying reserves at the time of the acquisitions, which is approximately 25 years.

The natural gas supply opportunities were acquired in conjunction with the 2003 North Texas system acquisition (see Note 3) and are recorded entirely in our Natural Gas segment. The value of the intangible asset was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. The natural gas supply opportunities are being amortized over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which is approximately 25 years.

The aggregate amortization expense for the years ended December 31, 2005, 2004 and 2003, were $3.7 million, $3.2 million, and $1.3 million, respectively. The estimated amortization expense for each year through December 31, 2010 is $3.6 million.

9. DEBT

The Partnership s debt consisted of the following:

	December 31,				
		2005		2004	
	Maturity	Rate	Dollars	Rate	Dollars
	(dollars in millions)				
First Mortgage Notes	2011	9.15 %	$ 186.0	9.15 %	$ 217.0
Senior Notes	2009-2034	5.70 %	1,198.6	5.66 %	1,198.4
Credit Facility	2010			2.05 %	175.0
Commercial Paper(1)	2010	4.36 %	329.3		
			$ 1,713.9		$ 1,590.4
Current maturities and short-term debt			(31.0)		(31.0)
Long-term debt			$ 1,682.9		$ 1,559.4

(1) Individual issues of commercial paper generally mature in 90 days or less, but are supported by our credit facility and are therefore considered long-term debt.

First Mortgage Notes

The First Mortgage Notes (Notes) are collateralized by a first mortgage lien on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. Property, plant and equipment attributable to the Lakehead Partnership are $1,384.2 million and $1,408.9 million as of December 31, 2005 and 2004, respectively. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We believe these restrictions will not negatively impact our ability to finance future expansion projects. Under the Notes agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 10) for the immediately preceding calendar quarter. If the Notes were to be paid prior to their stated maturities, the Note agreements provide for the payment of a redemption premium by the Partnership.

Under the terms of the Notes, we are required to establish, at the end of each quarter, a debt service reserve. This reserve includes an amount equal to 50% of the prospective Notes interest payments for the immediately following quarter and an amount for Note sinking fund repayments. At December 31, 2005 and 2004, there was no required debt service reserve, as all required interest and sinking fund payments had been made.

Senior Notes

All of the Senior Notes pay interest semi-annually and have varying maturities and terms as outlined below. The Senior Notes do not contain any covenants restricting the issuance of additional indebtedness and rank equally with all of our other existing and future unsubordinated indebtedness.

Senior Notes	**Interest Rate**	**December 31, 2005**	**2004**
	(dollars in millions)		
Senior Notes maturing in 2009	4.00 %	$ 200.0	$ 200.0
Senior Notes maturing in 2012	7.90 %	100.0	100.0
Senior Notes maturing in 2013	4.75 %	200.0	200.0
Senior Notes maturing in 2014	5.35 %	200.0	200.0
Senior Notes maturing in 2018	7.00 %	100.0	100.0
Senior Notes maturing in 2028	7.125 %	100.0	100.0
Senior Notes maturing in 2033	5.95 %	200.0	200.0
Senior Notes maturing in 2034	6.30 %	100.0	100.0
		$ 1,200.0	$ 1,200.0
Unamortized Discount		(1.4)	(1.6)
		$ 1,198.6	$ 1,198.4

Credit Facility

Our Credit Facility, as amended, is a five-year term facility that matures in April 2010 with a current borrowing capacity of $800 million and a letter of credit sub limit of $300 million. Additionally, subject to the approval of Enbridge Management s Board of Directors, we have the right to request an increase in commitments available under the Credit Facility up to an aggregate outstanding principal amount of $1 billion. We pay interest on the amounts outstanding at variable rates equal to the Base Rate or a Eurodollar Rate as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the facility. A facility fee is payable on the entire amount of the Credit Facility whether or not drawn. The facility fee also varies depending on our credit rating. Our Credit Facility contains restrictive covenants that require us to maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 5.25 times for twelve months through December 2006, at which time it decreases to 5.00 times, thereafter. At December 31, 2005, our interest coverage ratio was approximately 3.7 and our leverage ratio was approximately 4.2. Our Credit facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary. At December 31, 2005, we had no amounts outstanding under our Credit Facility and letters of credit totaling $149.3 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2005, we could borrow $320.7 million under the terms of our Credit Facility.

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our credit facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the years ended December 31, 2005, 2004 and 2003, we net settled borrowings of approximately $565 million, $1,573 million and $1,094 million, on a non-cash basis.

Commercial Paper Program

In April 2005, we established our $600 million commercial paper program that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. We repaid the entire amount previously outstanding under our Credit Facility with proceeds we obtained from issuing commercial paper under this program. Our Credit Facility remains undrawn and available to support our commercial paper program. Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. However, the amount of commercial paper we may issue is reduced by any balance of outstanding letters of credit in excess of $200 million. At December 31, 2005, we had outstanding $329.3 million of commercial paper, net of unamortized discount of $0.7 million, at a weighted average interest rate of 4.36% and outstanding letters of credit totaling $149.3 million. At December 31, 2005, we could issue an additional $270.0 million in principal amount under our commercial paper program.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying consolidated Statement of Financial Position.

Interest

For the years ended December 31, 2005, 2004, and 2003, interest expense is net of amounts capitalized of $4.0 million, $2.1 million, and $2.2 million, respectively. For each of the years ended December 31, 2005, 2004, and 2003, we made interest payments totaling $101.7 million, $73.9 million, and $69.1 million, respectively.

Maturities of Third Party Debt

The scheduled maturities of outstanding third party debt, excluding the market value of interest rate swaps, at December 31, 2005, are summarized as follows:

	(dollars in millions)
2006	$ 31.0
2007	31.0
2008	31.0
2009	231.0
2010	360.3
Thereafter	1,029.6
Total	$ 1,713.9

10. PARTNERS CAPITAL

Our capital accounts are comprised of a 2% general partner interest and 98% limited partner interests. The limited partner interests are comprised of Class A common units, Class B common units and i-units. The limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. The General Partner manages our operations, subject to a delegation of control agreement with Enbridge Management, and participates in the Partnership s distributions, including certain incentive income distributions.

Class A common units

The following table presents the net proceeds from our Class A common unit issuances for each of the years ended December 31, 2005, 2004 and 2003. The proceeds from each of the offerings were generally used to repay amounts outstanding under our credit facilities or commercial paper issued, which were initially issued to finance our capital expansion projects and acquisitions, or repayment of other outstanding obligations.

Issuance Date	**Number of Class A Common units Issued**	**Offering Price per Class A Common unit**	**Net Proceeds to the Partnership**(1)	**General Partner Contribution**(2)	**Net Proceeds Including General Partner Contribution**
	($ in millions, except per unit amounts)				
2005:					
December 2005	136,200	$ 46.000	$ 6.0	$ 0.2	$ 6.2
November 2005	3,000,000	$ 46.000	132.1	2.8	134.9
February 2005	2,506,500	$ 49.875	124.8	2.7	127.5
2005 Totals	5,642,700		$ 262.9	$ 5.7	$ 268.6
2004:					
September 2004	3,680,000	$ 47.900	$ 168.6	$ 3.6	$ 172.2
January 2004	450,000	$ 50.300	21.6	0.4	22.0
2004 Totals	4,130,000		$ 190.2	$ 4.0	$ 194.2
2003:					
December 2003	5,000,000	$ 50.300	$ 240.4	$ 5.0	$ 245.4
May 2003	3,850,000	$ 44.790	165.5	3.5	169.0
2003 Totals	8,850,000		$ 405.9	$ 8.5	$ 414.4

(1) Net of underwriters fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

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Class B common units

At December 31, 2005 and 2004, we had 3,912,750 Class B common units outstanding, which are held entirely by our general partner. Our Class B common units have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

i-units

The i-units are a separate class of our limited partner interests, all of which are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of our i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause us to be treated as a corporation for U.S. federal income tax purposes;
- Amendments to our partnership agreement that would have a material adverse effect on the holder of our i-units, unless, under our partnership agreement, the amendment could be made by our general partner without a vote of holders of any class of units;
- The removal of our general partner and the election of a successor general partner; and
- The transfer by our general partner of its general partner interest to a non-affiliated person that requires a vote of holders of units under our partnership agreement and the admission of that person as a general partner.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management s shares vote or refrain from voting their shares. Furthermore, under the terms of our partnership agreement, we agree that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

Distributions Paid

Our partnership agreement requires us to distribute 100% of our Available Cash , which is generally defined in our partnership agreement as the sum of all cash receipts and net additions to reserves for future requirements less cash disbursements and amounts retained by us. The reserves are retained to provide for the proper conduct of our business and as necessary to comply with the terms of our agreements or obligations (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). The distributions are made to our partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

Our General Partner is granted discretion by our partnership agreement, which discretion has been delegated to Enbridge Management, subject to the approval of the General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines the quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions of our Available Cash generally are made 98.0% to our Class A and B common unitholders and our i-unitholder and 2.0% to the General Partner. We will not distribute the cash related to the i-units, but instead, will distribute additional i-units such that the cash is retained and used in our business. Further, we retain an additional amount equal to 2.0% of the i-unit distribution from the General Partner to maintain its 2% general partner interest in us. Distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the unitholders are achieved. The incremental incentive distributions payable to the General Partner are

15.0%, 25.0% and 50.0% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B common units and i-units, respectively.

Typically, the General Partner and owners of our common units will receive distributions in cash. Enbridge Management, as the delegate of our general partner under the delegation of control agreement, computes the amount of our available cash. Enbridge Management, as owner of the i-units, however, does not receive distributions in cash. Instead, each time that the we make a cash distribution to the General Partner and the holders of our common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management s shares and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management s listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management s shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

The following table sets forth our distributions, as approved by the Board of Directors for each period in the years ended December 31, 2005, 2004 and 2003.

Distribution Declaration Date	Distribution Payment Date	Record Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i units to i unit holders(1)	Retained from General Partner(2)	Distribution of Cash
			(dollars in millions, except per unit amounts)				
2005							
October 26, 2005	November 14, 2005	November 3, 2005	$ 0.925	$ 64.1	$ 10.6	$ 0.2	$ 53.3
July 28, 2005	August 12, 2005	August 5, 2005	0.925	64.0	10.5	0.2	53.3
April 25, 2005	May 13, 2005	May 4, 2005	0.925	63.8	10.3	0.2	53.3
January 24, 2005	February 14, 2005	February 3, 2005	0.925	61.0	10.1	0.2	50.7
				$ 252.9	$ 41.5	$ 0.8	$ 210.6
2004							
October 22, 2004	November 12, 2004	November 1, 2004	$ 0.925	$ 60.7	$ 9.9	$ 0.2	$ 50.6
July 22, 2004	August 13, 2004	August 2, 2004	0.925	56.6	9.6	0.2	46.8
April 26, 2004	May 14, 2004	May 5, 2004	0.925	56.5	9.5	0.2	46.8
January 22, 2004	February 13, 2004	February 2, 2004	0.925	56.3	9.3	0.2	46.8
				$ 230.1	$ 38.3	$ 0.8	$ 191.0
2003							
October 22, 2003	November 14, 2003	November 4, 2003	$ 0.925	$ 50.5	$ 9.2	$ 0.2	$ 41.1
July 23, 2003	August 14, 2003	August 4, 2003	0.925	50.3	8.9	0.2	41.2
April 24, 2003	May 15, 2003	May 2, 2003	0.925	46.1	8.7	0.2	37.2
January 23, 2003	February 14, 2003	February 4, 2003	0.925	46.0	8.6	0.2	37.2
				$ 192.9	$ 35.4	$ 0.8	$ 156.7

(1) We issued 802,539, 840,239 and 833,515 i-units to Enbridge Energy Management, L.L.C., the sole owner of our i-units, during 2005, 2004 and 2003, respectively, in lieu of cash distributions.

(2) We retained an amount equal to 2% of the i-unit distribution from the General Partner to maintain its 2% general partner interest in us.

11. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and administrative, operations and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including the Partnership. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. There is no profit or margin for these services charged by Enbridge to its affiliates.

The portion of direct workforce costs associated with the management and administrative services provided at our Houston office and the operating and administrative services provided to support our facilities across the United States, are charged from Enbridge and its affiliates to us.

Certain of our operating activities associated with our Liquids segment are provided by Enbridge Pipelines Inc. (Enbridge Pipelines), a subsidiary of Enbridge, as the majority of these pipeline systems form one contiguous system with the Enbridge system in Canada. These services include control center operations, facilities management, shipper services, pipeline integrity management and other related activities. The costs to provide these services are allocated to us from Enbridge Pipelines, based on an appropriate allocation methodology consistent with Enbridge s corporate cost allocation policy, including estimated time spent and miles of pipe. We also receive costs associated with control center services for some of the natural gas assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to us pursuant to our partnership agreement and related services agreements. These costs are allocated to us based on an allocation methodology consistent with Enbridge s corporate cost allocation policy, including estimated time spent and headcount.

During 2005, 2004 and 2003, we incurred the following costs related to these services, which are included in operating and administrative expenses.

	Year ended December 31,		
	2005	**2004**	**2003**
	(dollars in millions)		
Direct workforce costs	$ 117.0	$ 101.7	$ 75.4
Liquids /Natural Gas operating costs	15.3	14.0	9.6
Allocated management and administrative costs, including insurance	20.1	17.2	14.2
	$ 152.4	$ 132.9	$ 99.2

Natural Gas Sales and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. Included in our results for the twelve months ending December 31, 2005, 2004 and 2003, are operating revenues of $43.6 million, $23.6 million, and $30.6 million, respectively, related to these sales.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Included in our results for the twelve months ending December 31, 2005, 2004 and 2003, are cost of natural gas expenses of $4.5 million, $6.9 million and $1.2 million, respectively, relating to these purchases.

Affiliate Notes

The Partnership has a note payable with an affiliate of Enbridge that totaled $151.8 million and $142.1 million at December 31, 2005 and 2004, which matures in 2007. The interest rate is 6.60% as of December 31, 2005 and 2004.

We incurred interest expense on affiliate notes totaling $9.7 million, $9.0 million, and $16.1 million for the years ended December 31, 2005, 2004, and 2003, respectively.

For the years ended December 31, 2005 and 2004, we converted interest payable related to loans from the General Partner and affiliates in the amount of $9.7 million and $9.0 million, respectively, into long-term loans from the General Partner and affiliates.

Incentive and Partnership Distributions

Pursuant to our partnership agreement, the General Partner owns an effective 2% general partner ownership interest in us. The General Partner received incentive distributions for the years ended December 31, 2005, 2004 and 2003 of $25.3 million, $22.9 million, and $19.2 million, respectively.

As of December 31, 2005 and 2004, the General Partner also owned 3,912,750 Class B common units, representing 5.8% and 6.5% ownership, respectively in us. The General Partner received cash distributions related to its ownership of Class B common units for the years ended December 31, 2005, 2004 and 2003 of $14.5 million, $14.4 million and $14.5 million, respectively.

Conflicts of Interest

Through a delegation of control agreement with the General Partner and us, Enbridge Management makes all decisions relating to the management and control of our business. The General Partner owns the voting shares of Enbridge Management and elects all of Enbridge Management s directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of the General Partner. Some of the General Partner s officers and directors are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of our unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, the General Partner, Enbridge and us. Our partnership agreement and the delegation of control agreement contain provisions that allow Enbridge Management to take into account the interest of parties in addition to those of our unitholders in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders, as well as provisions that may restrict the remedies available to unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

Enbridge Management

Pursuant to the delegation of control agreement between Enbridge Management, our General Partner and us, and our partnership agreement, we pay all expenses relating to Enbridge Management. This includes Texas franchise taxes and any other similar capital-based foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

12. ENVIRONMENTAL LIABILITIES

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

In connection with our acquisition of the Midcoast systems in October 2002, the General Partner has agreed to indemnify us and other related persons for certain environmental liabilities of which the General Partner has knowledge and which it did not disclose. The General Partner will not be required to indemnify us until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner s aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. We will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed.

As of December 31, 2005 and 2004, we have recorded $4.0 million and $3.6 million in current liabilities and $4.8 million and $5.3 million, respectively, in long-term liabilities primarily to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

In March 2004, we reduced our long-term environmental liabilities by $2.0 million related to certain of our Natural Gas assets. Since October 2002, during the time that these assets have been owned by us, we completed a review of the affected sites and determined that suspected contamination is less significant than originally estimated. Our assessment was based upon information gathered during the ownership period, existing technology, presently enacted laws and regulations and prior experience in remediating contaminated sites for similar assets.

13. COMMITMENTS AND CONTINGENCIES

Oil and Gas in Custody

Our Liquids assets transport crude oil and natural gas liquids owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline system at any one time approximates 25 million barrels, virtually all of which is owned by the Partnership s customers. Under terms of our tariffs, losses of crude oil from indentifiable incidents not resulting from our direct negligence may be apportioned among our customers. In addition, we maintain adequate property insurance coverage with respect to crude oil and natural gas liquids in our custody.

Approximately 50% of the natural gas volumes on our natural gas assets are transported for customers on a contractual basis. We purchase the remaining 50% and sell to third-parties downstream of the purchase point. At any point in time, the value of customers natural gas in the custody of our natural gas systems is not material to us.

Rate Refunds

On October 8, 2004, the FERC issued an Order on Remand (Remand Order) relating to initial rates on our Kansas Pipeline System (KPC) for the period of time between December 1997 and November 2002. We acquired KPC on October 17, 2002. The Remand Order was issued in response to a United States Court of Appeals ruling in August 2003 requiring the FERC to address the issue of appropriate rate refunds, if any, with respect to KPC s initial rates. In the Remand Order, the FERC found that the proper initial rates are lower than the rates previously charged to customers pending resolution of this contested rate case. In accordance with the FERC s findings, any difference between what was collected and the revised initial Section 7 rates for the period of time between December 1997 and November 2002, plus interest compounded quarterly, is subject to refund.

Refunds to our customers were made in January 2005 pursuant to a refund plan agreed upon with customers and approved by the FERC. Our Consolidated Statements of Income for the year ended December 31, 2004, includes a charge of approximately $13.6 million for the rate refunds and interest. The rate refunds relate almost entirely to a time period prior to our ownership of KPC.

Right-of-Way

As part of our pipeline construction process, we must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that we buy are capitalized as part of Property, Plant and Equipment. Right-of-way agreements that are leased from a third-party are expensed. We recorded expenses for the leased right-of-way agreements of $1.9 million, $1.8 million, and $1.4 million for the years ended December 31, 2005, 2004, and 2003, respectively.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

Future Minimum Commitments

As of December 31, 2005, the future minimum commitments having remaining non-cancelable terms in excess of one year are as follows:

Future Minimum Commitments	2006	2007	2008	2009	2010	Thereafter	Total
	(dollars in millions)						
Power and other purchase commitments	$ 70.4	$	$	$	$	$	$ 70.4
Other operating leases	4.2	4.2	4.0	3.5	1.1		17.0
Right-of-way(1)	1.8	1.7	1.7	1.8	1.8	44.7	53.5
Product purchase obligations(2)	62.8	59.9	36.6	31.8	28.0	116.7	335.8
Service contract obligations(3)	12.4	10.5	5.3	3.2			31.4
Total	$ 151.6	$ 76.3	$ 47.6	$ 40.3	$ 30.9	$ 161.4	$ 508.1

(1) Right-of-way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2010.

(2) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(3) The transportation service obligations represent the minimum payment amounts for firm transportation capacity reserved by the Partnership on third-party pipelines.

14. FINANCIAL INSTRUMENTS

Fair Value of Debt Obligations

The table below presents the carrying amount and approximate fair values of our debt obligations. The carrying amounts of our commercial paper approximate their fair values at December 31, 2005, due to the short-term nature of these obligations. The carrying amounts of our Credit Facility at December 31, 2004, approximate the fair values of this instrument because the variable interest rates on the amounts outstanding reprice frequently to reflect currently available interest rates. The fair values of the First Mortgage Notes and Senior notes have been determined based on quoted market prices for the same or similar issues.

	December 31, 2005		December 31, 2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$ 329.3	$ 329.3	$	$
Credit Facility			175.0	175.0
9.15% First Mortgage Notes	186.0	207.9	217.0	256.8
4.00% Senior notes due 2009	199.9	193.0	199.9	199.2
7.90% Senior notes due 2012	99.9	113.8	99.9	120.1
4.75% Senior notes due 2013	199.8	190.8	199.7	197.1
5.35% Senior notes due 2014	199.9	196.7	199.9	203.2
7.00% Senior notes due 2018	99.8	111.4	99.8	117.4
7.125% Senior notes due 2028	99.8	113.0	99.8	119.3
5.95% Senior notes due 2033	199.7	193.1	199.7	200.3
6.30% Senior notes due 2034	99.8	100.8	99.7	104.1

Fair Value of Derivative Financial Instruments

The fair values of our derivative financial instruments are determined based on available market information, valuation and modeling techniques. These modeling techniques require us to make estimates of future prices, price correlation, market volatility and liquidity. The estimates also reflect factors for time value of money and the volatility of prices underlying the contracts, the potential impact of liquidating positions in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of counter parties and operational risk.

Interest Rate Derivatives

We enter into floating to fixed interest rate swaps to manage the effect of future interest rate movements on our interest costs. We also enter fixed to floating rate interest rate swaps to manage the fair value of debt issuances. The following table summarizes our interest rate derivatives outstanding at December 31:

	Partnership Notional Principal (dollars in millions)	Pays	Receives	Maturity Date	Fair Value 2005 (dollars in millions)	2004
Floating to Fixed rate interest rate swaps:	30.0	3.18%	LIBOR	January 18, 2006	0.1	
	30.0	3.18%	LIBOR	January 20, 2006	0.1	
	30.0	3.20%	LIBOR	January 27, 2006	0.1	
	30.0	3.22%	LIBOR	January 30, 2006	0.1	
	30.0	3.21%	LIBOR	February 3, 2006	0.1	
	50.0	4.37%	LIBOR	June 1, 2013	1.0	(0.4)
	50.0	4.34%	LIBOR	June 1, 2013	1.1	(0.3)
	25.0	4.31%	LIBOR	June 1, 2013	0.5	(0.2)
Fixed to Floating rate interest rate swaps:	50.0	LIBOR-21bps	4.75%	June 1, 2013	0.2	1.8
	50.0	LIBOR-21bps	4.75%	June 1, 2013	0.2	1.8
	25.0	LIBOR-25bps	4.75%	June 1, 2013	0.2	1.0

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1%.

Our floating to fixed rate interest rate swaps maturing in 2006 qualify for and have been designated cash flow hedges of interest payments on $150 million of our variable rate indebtedness and therefore, the changes in fair value of these derivatives are recorded as an increase or decrease in Accumulated other comprehensive income. The floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 do not qualify as cash flow or fair value hedges and as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

Commodity Price Derivatives

The following table provides summarized information about the fair values of our outstanding commodity derivative financial instruments at December 31, 2005 and 2004:

		Wtd Avg Price		December 31, 2005 fair Value		December 31, 2004 Fair Value	
	Notional	Receive	Pay	Asset	Liability	Asset	Liability
Swaps							
Natural gas(1)							
Receive variable/ pay fixed	209,377,007	$ 9.73	$ 7.27	$ 511.0	$ (12.7)	$ 12.9	$ (72.4)
Receive fixed/ pay variable	263,866,039	6.79	9.92	15.1	(790.4)	66.9	(105.3)
Receive variable/ pay variable	25,553,581	9.38	9.26	8.0	(5.3)	0.7	(2.6)
NGL(2)							
Receive fixed/ pay variable	6,942,833	28.64	37.85		(60.3)	2.6	(16.3)
Crude(2)							
Receive fixed/ pay variable	1,376,479	45.69	62.72	0.2	(22.0)	1.1	(5.9)
Options calls							
Natural gas(1)	2,191,000	9.05	4.31		(9.5)		(9.3)
Options puts							
Natural gas(1)	1,826,000	8.71	3.40	0.1		0.9	
Totals(3)				$ 534.4	$ (900.2)	$ 85.1	$ (211.8)

(1) Notional amounts for natural gas are recorded in millions of British thermal units (MMBtu).

(2) Notional amounts for NGL and Crude are recorded in Barrels (Bbl).

(3) We record the fair value of our derivative financial instruments in the balance sheet as current and long-term assets or liabilities on a net basis by counterparty.

15. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows resulting from fluctuations in commodity prices and interest rates. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Accounting Treatment

All derivative financial instruments are recorded in our consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value (mark-to-market). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Transactions and Hedging Activities* (SFAS No. 133), if a derivative financial instrument does not qualify as a hedge or is not designated as a hedge, a change in the fair market value, both realized and unrealized, is recognized currently in our income statement as a derivative fair value gain (loss) and is recorded in Cost of natural gas for commodity derivatives and interest expense for interest rate derivatives.

Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to/from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the future physical transaction that underlies the derivative financial instrument occurs (e.g., purchase or sale of natural gas or interest payment).

If a derivative financial instrument is designated as a cash flow hedge and qualifies for hedge accounting, a change in the fair market value is deferred in Accumulated other comprehensive income (OCI), a component of Partners Capital, until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges and qualify for hedge accounting are included in Cost of natural gas in the period the hedged transaction occurs. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued, remain in OCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the noncash earnings volatility that arises under mark-to-market accounting treatment. To qualify for cash flow hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a fair value hedge of the change in fair market value of an underlying asset or liability, the gain (loss) resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain (loss) resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge s change in fair market value will be recorded in earnings as the amount that is not offset by the gain (loss) on the change in fair market value of the underlying asset or liability. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in interest expense. Similar to derivative financial instruments designated as cash flow hedges, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have three primary instances where the hedge structure does not meet the requirements to apply hedge accounting and, therefore, these financial instruments are considered non-qualified under SFAS No. 133. These non-qualified derivative financial instruments must be adjusted to their fair market value, or marked-to-market, each period, with the increases and decreases in fair value recorded as increases and decreases in Cost of natural gas in our Consolidated Statements of Income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and an associated financial instrument contract settlement is made.

The three instances of non-qualified hedges are as follows:

1. **Transportation** In our Marketing segment, when the pricing index used for gas sales is different from the pricing index used for gas purchases, we are exposed to relative changes in those two indices. By entering into a basis swap between those two indices, we can effectively lock in the margin on the combined gas purchase and gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, these types of derivative transactions do not qualify for hedge accounting under SFAS No. 133, as the ultimate cash flow has not been fixed, only the margin.

2. **Storage** In our Marketing segment, when we use derivative financial instruments to hedge market spreads around our owned or contracted assets, such as our gas storage portfolio, the underlying forecasted transaction may or may not occur in the same period as originally forecast. This can occur because we have the flexibility to make these changes in the underlying injection or withdrawal schedule, given changes in market conditions. Therefore, these transactions do not qualify for hedge accounting treatment under SFAS No. 133, as the forecasted transaction is no longer probable of occurring as originally set forth in the hedge documentation established at the inception of the hedge.

3. **Natural Gas Collars** In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of physical natural gas sales with a NYMEX pricing index to better match the indices, which was a sound economic hedging strategy. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are now accounted for in the Consolidated Statements of Income through mark-to-market accounting, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost basis rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the financial side of the transaction is recorded at fair market values while the physical side of the transaction is not) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Discontinuance of Hedge Accounting

During the second quarter of 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery points for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the second quarter of 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to Cost of natural gas on our Consolidated Statements of Income from OCI. Going forward, the derivative financial instruments for which hedge accounting has been discontinued are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out during the second quarter.

The following table presents the unrealized losses associated with changes in the fair value of our derivatives, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value losses	**December 31, 2005**	**December 31, 2004**	**December 31, 2003**
	(in millions)		
Natural Gas segment			
Ineffectiveness	$ 2.5	$ 1.1	$
Non-qualified hedges	5.6		
Marketing			
Non-qualified hedges	41.3	2.1	0.3
Discontinuance	9.0		
Derivative fair value losses	$ 58.4	$ 3.2	$ 0.3

De-designation and Settlement of Derivatives

In connection with the sale of assets, as discussed in Note 3 to these Consolidated Financial Statements, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that were qualified for and designated as cash flow hedges of forecasted sales of 273 Bbl/d of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bbl/d of NGLs through 2007.

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	December 31, 2005	**December 31, 2004**
	(in millions)	
Receivables, trade and other	$ 5.8	$ 8.2
Other assets, net	4.2	10.1
Accounts payable and other	(129.2)	(45.9)
Other long-term liabilities	(243.0)	(99.6)
	$ (362.2)	$ (127.2)

The increase in our obligation associated with our derivative activities from December 31, 2004 to December 31, 2005 is primarily due to the significant increases in forward natural gas and NGL prices. The Partnership s portfolio of derivative financial instruments is largely comprised of long-term fixed price sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in our OCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in OCI are unrecognized losses of approximately $8.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These unrealized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the twelve months ended December 31, 2005, and 2004 we reclassified unrealized losses of $33.8 million and $12.6 million from OCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled. We estimate that approximately $83.7 million of OCI representing unrealized net losses on cash flow hedging activities at December 31, 2005, will be reclassified to earnings during the next twelve months.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated BBB+ or better by the major credit rating agencies.

16. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following table presents certain financial information relating to our business segments as of and for the years ended December 31, 2005, 2004 and 2003.

	As of and for the Year Ended December 31, 2005				
	Liquids	**Natural Gas**	**Marketing**	**Corporate**(1)	**Total**
	(in millions)				
Total revenues	$ 418.0	$ 4,945.1	$ 3,884.2	$	$ 9,247.3
Less: Intersegment revenue		2,593.0	177.4		2,770.4
Operating revenues	418.0	2,352.1	3,706.8		6,476.9
Cost of natural gas		2,018.7	3,744.6		5,763.3
Operating and administrative	144.2	175.0	4.1	3.5	326.8
Power	74.8				74.8
Depreciation and amortization	71.7	66.0	0.5		138.2
Gain on sale of assets		(18.1)			(18.1)
Operating income	127.3	110.5	(42.4)	(3.5)	191.9
Interest expense				(107.7)	(107.7)
Rate refunds					
Other income				5.0	5.0
Minority interest					
Net income	$ 127.3	$ 110.5	$ (42.4)	$ (106.2)	$ 89.2
Total assets	$ 1,664.0	$ 2,145.9	$ 512.3	$ 106.2	$ 4,428.4
Capital expenditures (excluding acquisitions)	$ 77.0	$ 263.8	$ 0.2	$ 3.8	$ 344.8

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2004				
	Liquids	**Natural Gas**	**Marketing**	**Corporate**(1)	**Total**
	(in millions)				
Total revenues	$ 409.3	$ 2,890.1	$ 2,686.9	$	$ 5,986.3
Less: Intersegment revenue		1,570.2	124.4		1,694.6
Operating revenues	409.3	1,319.9	2,562.5		4,291.7
Cost of natural gas		1,031.8	2,555.3		3,587.1
Operating and administrative	128.9	138.3	3.4	3.5	274.1
Power	72.8				72.8
Depreciation and amortization	68.5	51.7	0.2	0.1	120.5
Gain on sale of assets					
Operating income	139.1	98.1	3.6	(3.6)	237.2
Interest expense				(88.4)	(88.4)
Rate refunds				(13.6)	(13.6)
Other income				3.0	3.0
Minority interest					
Net income	$ 139.1	$ 98.1	$ 3.6	$ (102.6)	$ 138.2
Total assets	$ 1,639.8	$ 1,717.2	$ 313.7	$ 100.0	$ 3,770.7
Capital expenditures (excluding acquisitions)	$ 81.9	$ 197.4	$ 0.3	$ 9.2	$ 288.8

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2003				
	Liquids	**Natural Gas**	**Marketing**	**Corporate**(1)	**Total**
	(in millions)				
Total revenues	$ 344.2	$ 2,079.8	$ 1,984.9	$	$ 4,408.9
Less: Intersegment revenue		1,121.3	115.3		1,236.6
Operating revenues	344.2	958.5	1,869.6		3,172.3
Cost of natural gas		754.9	1,857.8		2,612.7
Operating and administrative	104.1	102.3	2.2	3.2	211.8
Power	56.1				56.1
Depreciation and amortization	59.5	37.7	0.2		97.4
Gain on sale of assets					
Operating income	124.5	63.6	9.4	(3.2)	194.3
Interest expense				(85.0)	(85.0)
Rate refunds					
Other income				2.4	2.4
Minority interest					
Net income	$ 124.5	$ 63.6	$ 9.4	$ (85.8)	$ 111.7
Total assets	$ 1,511.2	$ 1,490.5	$ 189.6	$ 40.5	$ 3,231.8
Capital expenditures (excluding acquisitions)	$ 69.3	$ 55.4	$ 0.1	$ 4.5	$ 129.3

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

17. SUBSEQUENT EVENTS

Cash Distribution

On January 30, 2006, Enbridge Management s Board of Directors declared a distribution payable to our partners on February 14, 2006. The distribution was paid to unitholders of record as of February 7, 2006, of our available cash of $67.6 million at December 31, 2005, or $0.925 per common unit. Of this distribution, $56.6 million was paid in cash, $10.8 million was distributed in i-units to i-unit holders and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

18. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(dollars in millions, except per unit amounts)				
2005 Quarters					
Operating revenue	$ 1,250.1	$ 1,332.7	$ 1,809.6	$ 2,084.5	$ 6,476.9
Operating income	$ 53.2	$ 50.6	$ 11.9	$ 76.2	$ 191.9
Net income	$ 28.2	$ 25.7	$ (14.4)	$ 49.7	$ 89.2
Net income per common and i-unit(1)	$ 0.37	$ 0.32	$ (0.32)	$ 0.69	$ 1.06
2004 Quarters					
Operating revenue	$ 982.5	$ 969.7	$ 1,004.8	$ 1,334.7	$ 4,291.7
Operating income	$ 52.6	$ 58.0	$ 61.6	$ 65.0	$ 237.2
Net income	$ 33.1	$ 35.9	$ 27.6	$ 41.6	$ 138.2
Net income per common and i-unit(1)	$ 0.50	$ 0.56	$ 0.39	$ 0.61	$ 2.06

(1) The General Partner s allocation of net income has been deducted before calculating net income per common and i-unit.