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

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 2008

OR

☐ **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	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(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 ☒ No ☐

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 ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the 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 ☒ No ☐

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. ☐

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

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller reporting company ☐

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

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, 2008, was $3,008,976,552.

As of February 18, 2009 the Registrant has 76,088,834 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," "would," or "will" or the negative of those terms or other variations of them or by 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 or to make distributions 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
AOCI	Accumulated other comprehensive income
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
CNRL	Canadian Natural Resources Limited, an unrelated energy company
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of our 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 acquired on October 17, 2002.
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 and crude oil
EP Act	Energy Policy Act of 1992
EPACT	Energy Policy Act of 2005
EPA	Environmental Protection Agency
ERCB	Energy Resource Conservation Board, a successor regulatory body to the Alberta Energy Utility Board
Exchange Act	Securities Exchange Act of 1934, as amended
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, sold on November 1, 2007
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
M^3	Cubic meters of liquid = 6.2898105 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 region 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
NOPR	Notice of Proposed Rulemaking issued by the FERC
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 located in the Fort Worth Basin 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 I	Consists of Connecticut, Delaware, District of Columbia, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia and West Virginia
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	Fourth Amended and Restated Agreement of Limited Partnership of the Enbridge Energy Partners, L.P.
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration (formerly OPS)
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PIPES Act	Pipeline Safety Act Reauthorization of 2006
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 our Lakehead system
Settlement Agreement	A FERC approved settlement agreement, signed October 1996
SFAS	Statement of Financial Accounting Standards
SFPP	Santa Fe Pacific Pipelines, L.P., an unrelated pipeline company
Suncor	Suncor Energy Inc., an unrelated energy company
Syncrude	Syncrude Canada Ltd., an unrelated energy 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 our 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 our Lakehead system
TSX	Toronto Stock Exchange
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 New York Stock Exchange, or NYSE, under the symbol "EEP."

We were formed in 1991 by Enbridge Energy Company, Inc., 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 (the "System"). A subsidiary of Enbridge Inc., or Enbridge, owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, Canada 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, 2008, our portfolio of assets included the following:

- Approximately 5,300 miles of crude oil gathering and transportation lines and 28.9 million barrels, or Bbl, of crude oil storage and terminaling capacity;
- Natural gas gathering and transportation lines totaling approximately 11,700 miles;
- Nine active natural gas treating and 24 active natural gas processing facilities with an aggregate capacity of approximately 2,900 million cubic feet per day, or MMcf/d;
- Trucks, trailers and railcars for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide; and
- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management L.L.C., ("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. Our 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, 2008 and 2007 is comprised of the following:

	2008	2007
Class A common units owned by the public	51.2%	59.6%
Class A common units owned by our General Partner	13.9%	—
Class B common units owned by our General Partner	3.4%	4.2%
Class C units owned by our General Partner	5.5%	6.4%
Class C units owned by institutional investors	11.3%	13.1%
i-units owned by Enbridge Management[1]	12.7%	14.7%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) The General Partner owns 17.2% of the total i-units owned by Enbridge Management.

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 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. Focus on operational excellence
   - We 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.
2. Expand existing core asset platforms
   - We intend to develop 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.
3. 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.

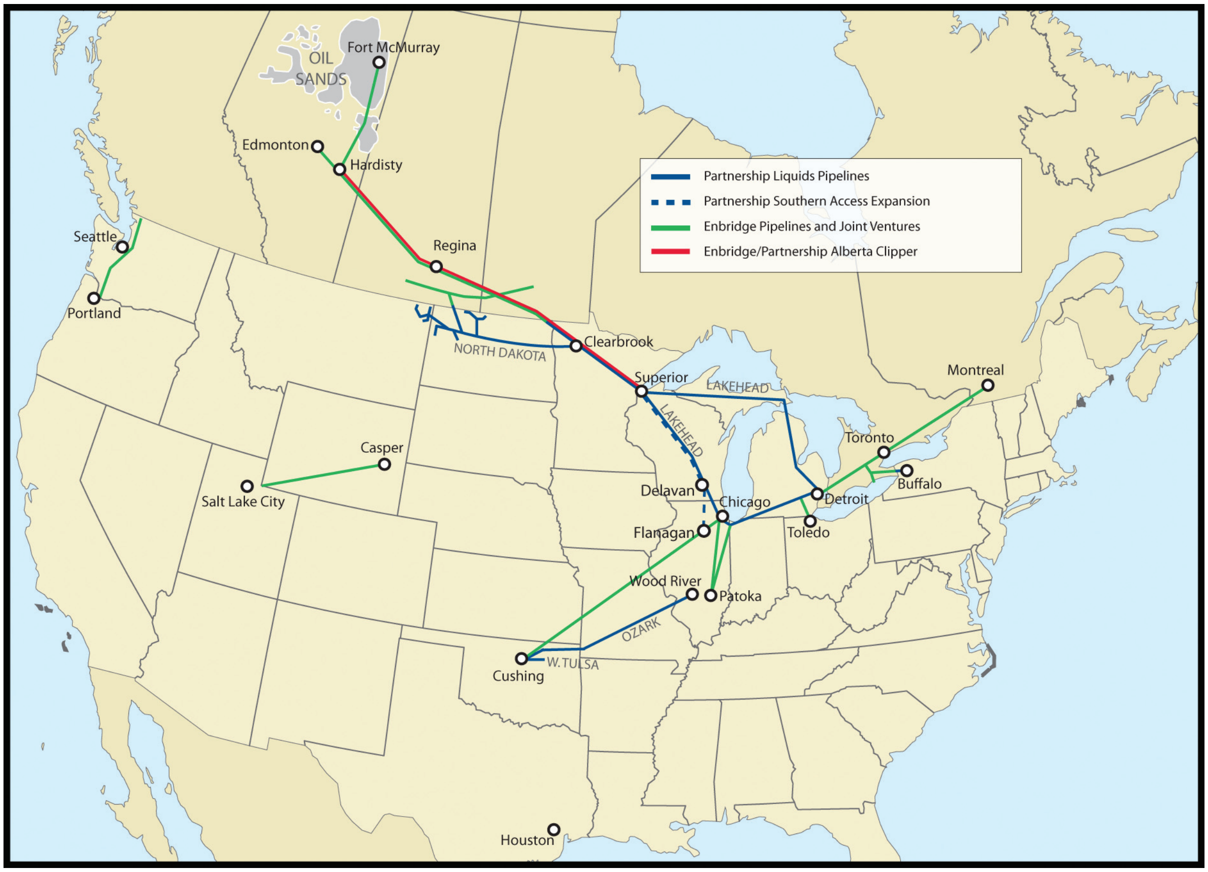
In our current environment, our primary focus is on effective and efficient operation of our current assets and completion of our major liquids capital expansions. We remain committed to growing our natural gas and liquids business through a disciplined spending approach on new capital projects. We continue to place minimal emphasis on acquisitions. While the current economic environment remains volatile, our acquisitions will likely be limited to situations where we have natural advantages, through reduced costs or increased utilization of our services.

Volatility in the capital markets will necessitate a less aggressive capital program in our natural gas business in the near term. During this period of volatility we will continue to focus our efforts primarily on the development of our existing pipeline systems. We have evaluated all of our planned future Natural Gas projects and have written off projects that were uneconomic. We have also delayed other projects until such time that capital becomes available at more economical costs for those projects with sufficient commercial support. We will opportunistically evaluate strategic prospects to further expand the service capabilities of our existing system. We may also pursue opportunities to divest any non-strategic natural gas assets as conditions warrant.

Our planned internal growth for our liquids business will require a significant investment of expansion capital over the next two years. While these major projects are under construction, we will bear the associated capital costs for these investments before we begin to realize a return on them. We expect our larger growth projects will be accretive to distributable cash flow when placed into service in 2009 and 2010. These projects are discussed below in the respective business section.

Liquids

The map below presents the locations of our current Liquids systems assets and projects being constructed. This map depicts some assets owned by Enbridge and projects being constructed to provide an understanding of how they interconnect with our Liquids systems.



Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2008 from the U.S. Department of Energy's Energy Information Administration, Canada supplied approximately 1.9 million Bpd of crude oil to the U.S., the largest source of U.S. imports. Approximately 67 percent of the Canadian crude oil moving into the U.S. was transported on the System. We are well positioned to develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta oil sands. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. The Canadian Association of Petroleum Producers' ("CAPP") December 2008 estimates of future production from the Alberta Oil Sands is expected to grow steadily during the next 10 years, with an additional 1.8 million Bpd of incremental supply available by 2018, based on a subset of currently approved applications and announced expansions.

Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply of western Canadian crude oil. Our $2.1 billion project will provide an additional 400,000 Bpd of heavy crude oil capacity to the Chicago, Illinois market and beyond by early 2009. The first stage, a new 42-inch diameter pipeline from Superior to Delavan, Wisconsin, was completed and placed into commercial service and ready to receive linefill at the end of the first quarter of 2008. We began filling the pipeline in the fourth quarter of 2008 and will continue through the first quarter of 2009 as crude oil is made available by shippers. The first stage of the expansion added capacity of approximately 190,000 Bpd to the pipeline and system-wide toll surcharges were effective April 1, 2008 for the facilities that we have placed into service. In June 2008, we commenced construction on the second stage of the expansion project. This stage consists of a new pipeline from Delavan to Flanagan, Illinois which we expect to be complete by April of 2009. The design permits a further 800,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior. The Southern Access project also involves expansion on the Canadian portion of the system owned by Enbridge.

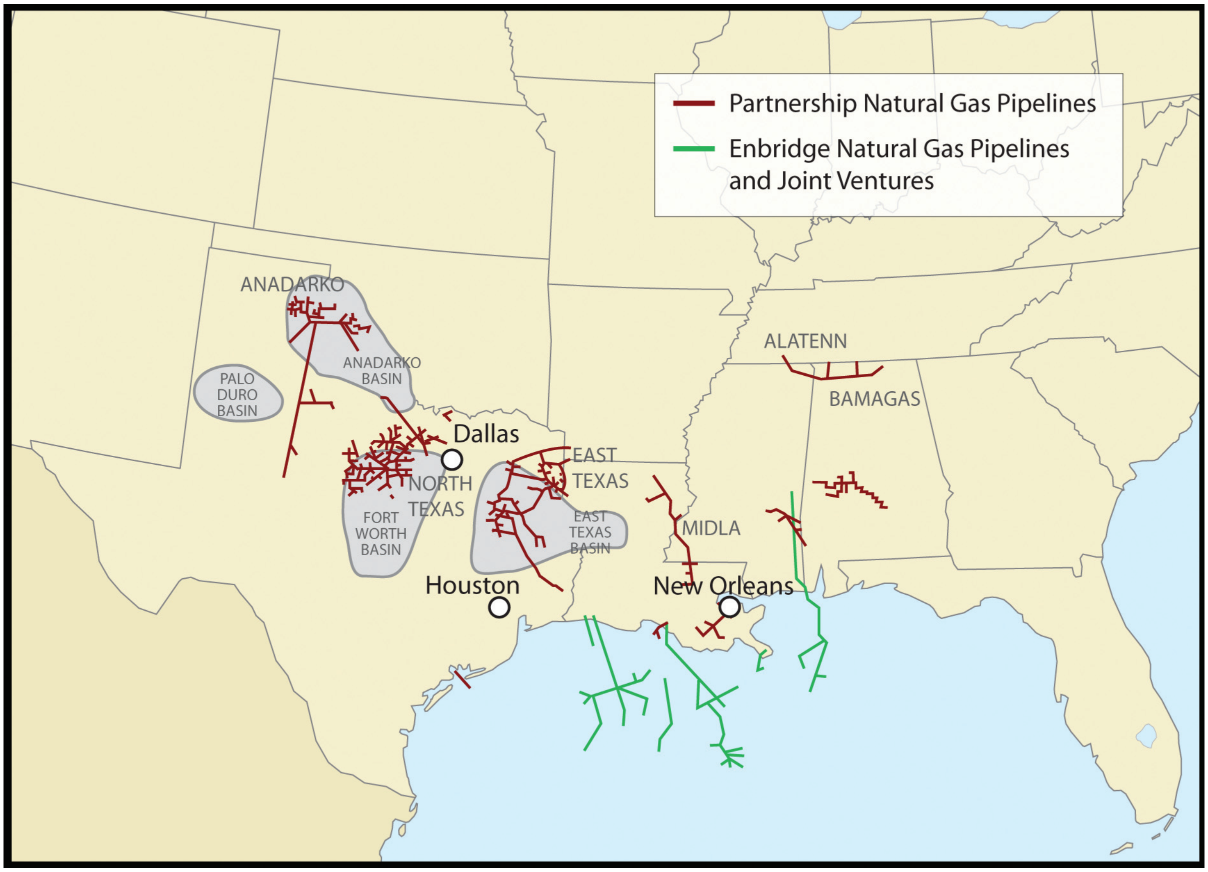
We and Enbridge are also developing the Alberta Clipper pipeline project, which will involve construction of a 1,000 mile, 36-inch diameter, heavy crude oil pipeline from Hardisty, Alberta to Superior with an initial capacity of 450,000 Bpd that is expandable to 800,000 Bpd. Our share of the cost of this project will be approximately $1.2 billion dollars. In Canada, the National Energy Board, or NEB, approved the project in the first quarter of 2008 with construction commencing in August of that year. In the United States, regulatory and permit applications are progressing at state and federal levels. Construction in the United States is expected to commence in mid-2009.

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 the Midwest area of the United States ("PADD II") as well as entry into the vast refining center of the U.S. Gulf Coast ("PADD III").

The strategy of further penetration into PADD II is evidenced by the Enbridge expansion of the Spearhead pipeline system from 125,000 Bpd to 193,300 Bpd, which is expected to be completed in early 2009. Our Lakehead system carries western Canadian crude oil as far as Chicago, where it is transferred to the Spearhead pipeline that runs from Chicago to the storage hub located at Cushing.

Natural Gas

The map below presents the locations of assets for our Natural Gas systems. This map depicts some assets owned by Enbridge to provide an understanding of how they relate to our Natural Gas systems.



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 consistent drilling and production growth. These core basins are known as the East Texas basin, the Fort Worth Basin and the Anadarko basin. Our focus has primarily been on developing and expanding the service capability of our existing pipeline systems.

One of our key goals 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 strategies are to provide safe and reliable service at reasonable costs to our customers, enhance our reputation and capitalize on opportunities for attracting new customers. From a commercial perspective, our focus is to provide our customers with a greater value for their commodity. This latter objective we intend to achieve by increasing customer access to preferred natural gas markets. We have made significant progress on attaining this objective with the construction of our East Texas Expansion project, otherwise known as Clarity, which includes an intrastate pipeline connecting our East Texas system at Bethel, Texas to multiple downstream interconnects and by physically connecting a number of our systems. The aim 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, which Clarity provides. From these market hubs, natural gas can be used in the local Texas markets or transported to consumers in the Midwest, Northeast and Southeast United States.

Our Natural Gas business also includes trucking, rail and liquids marketing operations that we use to enhance the value of the NGLs produced at our processing plants. Our Natural Gas Marketing business provides us with the ability to 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 are primarily the result of historically strong commodity prices, rig utilization rates 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, new pipelines and treating plant re-activations. However, growth prospects have been hindered by the current commodity price environment.

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. We coordinated extensively with our customers to develop and enhance access for growing Texas natural gas production, inclusive of the Bossier Sands Formation, to major markets in southeast Texas. The project was successfully completed in late 2008 with its final compressor station coming on-line in early 2009. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

In addition to the expansion of our transportation capacity to meet the needs of our customers, we have also expanded our processing and treating capacity on our East Texas system to meet the growing demand for these services and to capture the additional revenue these services provide. In 2008 our expansion of the Aker treating plant was completed and placed into service adding 125 MMcf/d of treating capacity to the East Texas system. Also in the third quarter of 2008, we commenced construction on a $60 million expansion project to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. As part of the expansion project we have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. Additional compression capacity will continue to be added until the project's completion in 2009.

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 17 of our consolidated financial statements beginning on page F-1 of this report.

Liquids Segment

Lakehead system

Our Lakehead system consists primarily of a crude oil and liquid petroleum common carrier pipeline and terminal 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 55 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. We and Enbridge have undertaken the Southern Access, Alberta Clipper and other expansion projects to increase the capacity of our Lakehead and Enbridge's mainline systems in an effort to capitalize on the 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 an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission, or FERC. Our Lakehead system spans a distance of approximately 1,900 miles, and consists of approximately 3,800 miles of pipe with diameters ranging from 12 inches to 48 inches, 60 pump station locations with a total of approximately 846,450 installed horsepower and 64 crude oil storage tanks with an aggregate capacity of approximately 11.6 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 43 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 2008, approximately 33 shippers tendered crude oil and liquid petroleum for delivery through our Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our 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. The NEB estimated that total production in 2008 from the Western Canadian Sedimentary Basin, or WCSB, averaged approximately 2.40 million Bpd compared with 2.35 million Bpd in 2007. Volumes of WCSB crude oil production are comparable with production volumes from Kuwait and Venezuela, key members of the Organization of Petroleum Exporting Countries, or OPEC.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.7 billion barrels at the end of 2006. During 2006, the latest period for which data is available, approximately 66 percent of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta oil sands as of the end of 2007 stand at approximately 173 billion barrels. Combined conventional and oil sands established reserves of approximately 178 billion barrels compares with Saudi Arabia's proved reserves of approximately 264 billion barrels.

According to the CAPP, an estimated $77 billion CAD has been spent on oil sands development from 1997 through 2007. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. CAPP's December 2008 estimates of future production from the Alberta Oil Sands is expected to grow steadily during the next 10 years, with an additional 1.8 million Bpd of incremental capacity available by 2018, based on a subset of currently approved applications and announced expansions.

The near-term growth in crude oil supply comes from the completion and consolidation of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new Steam Assisted Gravity Drainage, or SAGD, facilities currently under construction. Over the next year, synthetic crude oil production is expected to increase by approximately 269,500 Bpd from the following sources:

- 114,000 Bpd from the phase 1 start up by Canadian Natural Resources Limited ("CNRL") of its Horizon Project Upgrader;
- 58,500 Bpd from the phase 1 start-up of the Long Lake Project upgrader by joint venture partners Nexen Inc. and OPTI Canada Inc.; and
- 97,000 Bpd from start-up of the Millennium coker unit by Suncor Energy Inc.

Syncrude completed its 100,000 Bpd Stage 3 expansion in 2006, increasing total production capacity to 350,000 Bpd. Extreme cold weather in the first quarter of 2008 and coker turnarounds in the second and third quarters of 2008 led to average production of 283,000 Bpd, which is 19,000 Bpd lower than 2007. Syncrude's next expansion will be the Stage 3 debottleneck to increase their current system synthetic production by approximately 50,000 Bpd, with a projected in-service date of 2012.

Suncor completed expansion on one of its upgraders in the third quarter of 2008, resulting in total upgrading capacity of approximately 350,000 Bpd. However, Suncor is expecting to ramp up production to its 350,000 Bpd design capacity in 2009. Synthetic production averaged approximately 226,000 Bpd in 2008, which was 3,000 Bpd lower than in 2007. Suncor also received conditional approval from the Energy Resource Conservation Board ("ERCB"), successor to the Alberta Energy Utility Board, for its proposed Voyageur expansion, which was planned to increase synthetic production capacity to 550,000 Bpd by 2012. Suncor recently announced that it has wound down construction on its Voyageur upgrader and Stage 3 Firebag project, and put them into "safe mode" pending recommencement of expansion work.

The Athabasca Oil Sands Project, or AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Corporation (20%), is another oil sands project that reached full production capacity in 2004. An expansion of the AOSP project moved forward with ERCB's conditional approval of the AOSP Expansion 1 project in 2006. The AOSP Expansion 1 project aims to increase the current production capacity of 158,000 Bpd of synthetic crude oil to more than 249,000 Bpd by 2010.

Over the next two years, over 20 individual projects are expected to come on-line that should start, or increase the production of unblended bitumen. Notable projects include the expansions at CNRL's Wolf Lake/ Primrose area, MEG Energy Corp's Christina Lake, StatoilHydro's Kai Kos Dehseh, EnCana's Foster Creek and Christiana Lake, Husky's Caribou Lake, Suncor's Firebag and Total's Josyln project. Based on the ERCB forecast, unblended bitumen production is expected to increase by roughly 57,000 Bpd by the end of 2010.

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

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

The United States Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated natural gas resources of the Upper Devonian—Lower Mississippi Bakken formation in the United States portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil. Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. As a result, we have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the FERC in October 2008. The Phase VI expansion is expected to be in service in early 2010.

Based on forecasted growth in western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, our Lakehead system deliveries are expected to average 1.74 million Bpd in 2009 compared with 1.62 million Bpd in 2008.

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 our Lakehead system. Deliveries on our 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 that demand for WCSB crude oil production will continue to increase in PADD II. Refinery configurations and crude oil requirements in PADD II continue to be an attractive market for western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, 2008 demand for crude oil in PADD II remained flat from 2007 with an average of 3.2 million Bpd. At the same time, production of crude oil within PADD II increased by 55,000 Bpd to 527,000 Bpd. With the proximity of the WCSB to PADD II, the availability of capacity on our Lakehead system and limited alternative markets for WCSB production, we expect deliveries on our 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 of crude oil from the WCSB.

The projected growth in western Canadian crude oil production will require construction of new pipelines to ensure expanding oil supplies can be transported to markets in the United States. We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets in the United States. Crude oil price volatility in 2008 has caused some oil sands producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals of oil sands projects are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the WCSB declines, immediate need for new pipeline infrastructures will likely decline and our Southern Access and Alberta Clipper expansions may provide sufficient capacity for the near-term. If this is the case, we expect expansion activities in and around our Lakehead system to continue but they may be more modest than experienced over the last several years. For an overview of our projects refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations by Segment—Liquids—Future Prospects for Liquids."

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 PADD II, the Rocky Mountain states (PADD IV), the Anacortes area of Washington State (PADD V), and the U.S. Gulf Coast (PADD III). In each of these regions, WCSB crude oil competes with local and imported crude oil. As local crude oil production declines and refineries demand more imported crude oil, imports from the WCSB should increase.

For 2008, the latest data available shows that PADD II total demand was 3.2 million Bpd while it produced only 527,000 Bpd, and thus imported 2.7 million Bpd. The 2008 data indicates PADD II imported approximately 1.2 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead system to destinations in PADD II and to other pipeline systems with PADD III destinations. The remaining 1.5 million Bpd were imported from PADDs III and IV as well as from offshore sources through the U.S. Gulf Coast. Lakehead system deliveries of Canadian crude oil to PADD II were 54,900 Bpd higher than delivery volumes for 2007. Total deliveries on our Lakehead system averaged 1.62 million Bpd in 2008, meeting approximately 72 percent of Minnesota refinery capacity; 64 percent of the greater Chicago area; and 68 percent of Ontario's refinery demand.

Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 67 percent of the total western Canadian crude oil exports in 2008 to the United States. The remaining production was transported by systems serving the British Columbia, PADD II, PADD IV, and PADD V markets.

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 crude oil producers. These proposals range from expansions of existing pipelines that currently transport western Canadian crude oil, to new pipelines and extensions of existing pipelines. These proposals are in various stages of development, with some at the concept stage and others that are proceeding with regulatory approval. Some of these proposals could be in direct competition with our Lakehead system.

Enbridge has proposed construction of the Gateway Pipeline with an in-service date in the 2014 to 2015 timeframe, which includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat and would compete with our Lakehead system for production from the Alberta oil sands.

We and Enbridge believe that the Southern Access Expansion Program, the Alberta Clipper Project, 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.

The following provides an overview of other proposals put forth by competing pipeline companies that are not affiliated with Enbridge:

- The construction of a new 24-inch pipeline alongside an existing pipeline which begins in Clearbrook and transports western Canadian crude oil to St. Paul, Minnesota. This expansion will have 165,000 Bpd initial capacity and 350,000 Bpd ultimate capacity. Construction began in the summer of 2007, and was completed in September 2008. While throughput on our Lakehead system would benefit from this expansion, volumes moving on our Lakehead system could be negatively impacted if the geographic reach of this pipeline were extended by reversing an existing Wood River to St. Paul pipeline.
- 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 was completed in 2007. The second phase received NEB approval in October 2006 and was completed in November 2008, adding another 40,000 Bpd of capacity.
- Construction of a new 435,000 Bpd crude oil pipeline from Hardisty to Wood River and Patoka, with a proposed in-service date of late 2009. In September 2007 the NEB approved the application to construct and operate a 435,000 Bpd crude oil pipeline. In March 2008, the U.S. Department of State issued a Presidential Permit for construction, operation, and maintenance of the pipeline. A successful open season was held in the early part of 2007 for an expansion to 590,000 Bpd and an extension to Cushing. The project has received 495,000 Bpd in long-term commitments. In July 2008, the NEB approved the 435,000 Bpd to 590,000 Bpd expansion. Commercial support has been announced to construct a 36-inch crude oil pipeline extension to this system that will begin at Hardisty and extend down to Cushing and then to Nederland, Texas. The extension will add an additional 500,000 Bpd of capacity with a targeted in-service date of 2012. The proposed pipeline extension received 380,000 Bpd of shipper support in the third quarter of 2008. A variety of regulatory approvals will be required in the United States and Canada before the proposed extension can proceed.

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

The following table sets forth average deliveries per day and barrel miles of our Lakehead system for each of the periods presented.

	Deliveries				
	2008	2007	2006	2005	2004
	(thousands of Bpd)				
United States					
Light crude oil	388	346	327	241	275
Medium and heavy crude oil	876	852	872	791	785
NGL	3	4	5	4	4
Total United States	1,267	1,202	1,204	1,036	1,064
Ontario					
Light crude oil	183	184	160	146	174
Medium and heavy crude oil	80	62	63	59	81
NGL	90	95	90	98	103
Total Ontario	353	341	313	303	358
Total Deliveries	1,620	1,543	1,517	1,339	1,422
Barrel miles (billions per year)	432	408	400	338	367

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. Our Mid-Continent system includes over 480 miles of crude oil pipelines and 16.7 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 106 individual storage tanks ranging in size from 55,000 to 575,000 barrels. We added a net of seven new tanks during 2007 to our existing storage facilities in Cushing, which increased our crude oil storage capacity to 16.7 million barrels. A portion of the storage facilities are used for operational purposes while for the remainder of the facilities, we contract with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge 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 2008, approximately 33 shippers tendered crude oil for service by our Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average deliveries on the system were 231,000 Bpd for 2008 and 236,000 Bpd for 2007.

Supply and Demand. Our Mid-Continent system is positioned to capitalize on 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 2008, PADD II imported 2.7 million Bpd from outside of the PADD II region. The 2008 data indicate PADD II imported approximately 1.2 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead System. The remaining 1.5 million Bpd of crude oil were imported from PADDs III and IV as well as 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 our 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 the U.S. Gulf Coast and foreign supply through the Capline pipeline system, which is an undivided joint interest pipeline that is owned by unrelated parties. In addition, refineries located east of Patoka with access to crude oil through our Ozark system, also have access to west Texas supply through the West Texas Gulf / Mid-Valley pipeline systems owned by unrelated parties. Our Ozark pipeline system could face a significant increase in competition when a competitor's new pipeline from Hardisty to Patoka is completed in late 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, western Canadian crude oil moving on Spearhead is increasing the importance of Cushing as a terminal and pipeline origination area.

Competition to our West Tulsa pipeline increased with the introduction of new capacity into Tulsa from Cushing by unrelated parties shipping portions of a local refinery's supply through a reactivated pipeline in advance of planned refinery expansion plans. This new line was created by modifying existing infrastructure.

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. The crude oil gathering pipelines of our North Dakota system collect crude oil from points near producing wells in approximately 22 oil fields in North Dakota and Montana. Most deliveries from our North Dakota system are made at Clearbrook to our Lakehead system and to a third-party pipeline system. Our 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 110,000 Bpd. We recently completed a 30,000 Bpd increase in capacity resulting from the $78.2 million Phase V expansion of the system which we began in 2006 and completed in December 2007. This expansion was necessary to meet increased crude oil production from the Montana and North Dakota region. We have also initiated construction of an approximate $150 million additional expansion to further increase system capacity to 161,000 Bpd which we refer to as the Phase VI expansion. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing indexed tariff rates. The proposed surcharge is similar to the structure being used on the recently completed expansion project and is subject to approval from the FERC. Our North Dakota system also has 21 pump stations, one delivery station, and 11 terminaling facilities with an aggregate working storage capacity of approximately 745,000 barrels.

Customers. Customers of our North Dakota system include refiners of crude oil, 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. Similar to our Lakehead system, our 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. Due to increased exploration of the Bakken Formation within the Williston Basin, the North Dakota region has seen increased production levels up to 202,000 Bpd in December 2008.

Competition. Competitors of our 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 our North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities, including some existing rail loading facilities.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking, rail and liquids marketing operations. We purchase and gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission 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, 2008, we have nine active treating plants and 24 active processing plants, including three hydrocarbon dewpoint control facilities, or HCDP plants. Our treating facilities have a combined capacity exceeding 1,180 MMcf/d while the combined capacity of our processing facilities approximates 1,800 MMcf/d, including 550 MMcf/d provided by the HCDP plants.

Our natural gas segment consists of the following systems:

- East Texas system: Includes approximately 3,900 miles of natural gas gathering and transportation pipelines, eight natural gas treating plants and seven natural gas processing plants, including three HCDP plants and approximately 260 miles of pipeline associated with completed sections of our Clarity project.
- Anadarko system: Consists of approximately 1,800 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle and six natural gas processing plants. The Anadarko system includes the Palo Duro system, which we acquired in March 2004.
- North Texas system: Includes approximately 4,500 miles of natural gas gathering pipelines and ten natural gas processing plants located in the Fort Worth Basin.
- Our transportation operations include three FERC-regulated natural gas interstate pipeline systems which include the Midla, AlaTenn and UTOS pipelines. Each of these natural gas pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers. Effective January 1, 2009, UTOS was sold to Enbridge Offshore (Gas Transportation), LLC, a wholly-owned subsidiary of Enbridge.
- Our transportation operations also include a number of smaller non-FERC regulated natural gas pipelines and plants as well as trucking operations which are discussed below.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers are comprised of marketers, including our Marketing business, 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 predominantly in the U.S. Gulf Coast and southeastern 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. Due to the current weak commodity price environment, we expect that near-term demand may decrease. Two of our larger systems, East Texas and North Texas, 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. The Bossier trend, which is located on the western side of our East Texas system within the East Texas Basin, continues to experience substantial growth. Production in the Bossier trend has grown from under 390 MMcf/d in 1997 to over 2,290 MMcf/d in November 2008. Another factor that could lead to more demand on our services is the recent discovery of the Haynesville Shale in western Louisiana and eastern Texas. The Haynesville Shale has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system increasing the demand for our services.

During 2006, a link between our North Texas and East Texas systems became fully operational and increased the utilization of the 500 MMcf/d intrastate pipeline that we placed in service in June 2005 on our East Texas system by providing additional market access to customers of our North Texas system. In a further effort to address the continuing strong growth in natural gas production occurring in east Texas, in early 2006, we initiated a $655 million expansion and extension of our East Texas system named the Clarity project. During 2008, we successfully completed the Clarity project with the following portions of this expansion project being completed throughout the year:

- The Goodrich compressor station was constructed and placed into service in December 2008;
- A 20-inch segment from Orange County, Texas to a downstream interconnect near Beaumont, Texas, enabling deliveries into the interconnect, was placed into service in December 2008; and
- A 36-inch diameter pipeline segment that extends from Kountze, Texas to Orange County was placed into service in July 2008.

Construction of the Orange County compressor station is nearly complete and is expected to be placed into service in late February 2009. Additional capacity to downstream interconnects will increase as compression continues to be added through mid-2009. Now that our Clarity project has been completed, we will be able to provide service to major industrial companies in southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. The Clarity project is designed to be expandable and is positioned for potential upstream and downstream extension to meet the growing demand for natural gas transportation capacity.

We have also completed further expansion of our treating and processing capacity in the region, which began in 2006 with the completion of our 120 MMcf/d Henderson natural gas processing facility. In May 2008, our expansion of the Aker treating plant on our East Texas system was completed and placed into service, adding 125 MMcf/d of treating capacity. In the third quarter of 2008, we commenced a $60 million expansion project to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. As part of the expansion project, we have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. Additional compression capacity will continue to be added until the project's completion in 2009. When complete the expansion will provide an additional 160 MMcf/d of capacity for this growing region.

The gathering, treating, processing and transportation assets we have placed into service over the past several years on our East Texas system are well positioned to capture the growing supply of natural gas being produced in the region. This is a result of the improved access to primary natural gas markets provided by our Clarity project and other expansion projects. We expect the volumes on our East Texas system will increase over the next several years as producers take advantage of new drilling opportunities, including the Haynesville Shale discovery.

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, technological advances in fracturing the shale formation allow commercial production of these natural gas reserves. Based on the latest information available for 2008, Barnett Shale production has risen from approximately 110 MMcf/d in 1999 to over 4,690 MMcf/d in November 2008, with the drilling of over 10,300 wells. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of continued Barnett Shale development. This is a result of producers balancing the economics of lower commodity prices with the prolific drilling opportunities of the Barnett Shale.

Our Anadarko system is located within the Anadarko basin and has experienced considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. However, we expect the volumes on our Anadarko system to decline from historic levels due to weak commodity prices in the Midcontinent region of the United States, among other economic factors.

Volatility in the capital markets will necessitate a less aggressive capital program in our natural gas business in the near-term. During this period of volatility, we will continue to focus our efforts primarily on the development of our existing pipeline systems. We have evaluated all of our planned future Natural Gas projects and have written off projects that were uneconomic. We have also delayed other projects until such time that capital becomes available at more economical costs for those projects with sufficient commercial support. We will opportunistically evaluate strategic prospects to further expand the service capabilities of our existing system. We may also pursue opportunities to divest any non-strategic natural gas assets as conditions warrant.

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. 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, 2008, approximately 74 percent of contracted capacity of the Midla system and approximately 12 percent of the AlaTenn system is under contract to our marketing business. We completed negotiations with a major customer of our Midla mainline transmission system for the renewal of a contract that expired in August 2008 for another five year term. Unlike our gathering systems, our interstate pipelines have a concentration of customers. As such, they are more susceptible to contract loss or competition and potentially the inability to recover the carrying value of their noncurrent assets.

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 contracts. The average daily throughput on our UTOS system during 2008 was 128,000 MMBtu/d. The FERC approved our negotiated settlement with UTOS shippers, keeping our current rates in effect under our 2003 FERC Order through 2009. Effective January 1, 2009, we sold our UTOS system to Enbridge Offshore (Gas Transportation), LLC, a wholly-owned subsidiary of Enbridge.

Results of our Natural Gas business depend upon the drilling activities of natural gas producers in the areas we serve. We expect the rapid decline in natural gas and NGL prices during the second half of 2008 to reduce exploration and production activity by natural gas producers in the near term, which may diminish the growth rate of our Natural Gas business. Specifically, we expect the volumes on our Anadarko system to decline from historic levels due to weak commodity prices in the Midcontinent region of the United States, among other economic factors. However, our East Texas and North Texas systems are located in two areas where we believe producers are likely to remain active due to the higher probability of success associated with resource developments in these areas. We believe the higher success rate in these two areas, coupled with the recent natural gas discovery of the Haynesville Shale, should temper the impact of lower natural gas production that generally results from a reduction in drilling activity.

Competition. Competition from other pipeline companies is significant in all the markets we serve. 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. In addition, a number of new interstate natural gas pipelines are being constructed in areas currently served by some of our intrastate and interstate pipelines. When completed, these new pipelines may compete for customers with our existing pipelines.

Trucking and Liquids Marketing Operations

We also include our trucking and liquids marketing operations in our Natural Gas segment. These 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 and liquids marketing operations resell 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 43 percent of the volume transported by our trucking and liquids marketing 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 2008, we acquired the assets of a common carrier trucking company for $7 million 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 U.S. Gulf Coast customers. This acquisition doubled the size of our truck fleet.

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

Supply and Demand. Supply is sourced from a variety of areas in the U.S. Gulf Coast, with a significant amount of the NGL volume coming from our own gathering and processing facilities. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for our 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 and liquids marketing 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 and liquids marketing operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment's primary objectives are to mitigate financial risk and maximize the value of the natural 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, Mississippi and Louisiana, the majority of activities conducted by our Marketing segment are focused within these areas.

Customers. Natural gas purchased 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 third-party 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. This capacity is leased for various lengths of time and at rates that allow our Marketing business to diversify its customer base by expanding its service territory. Additionally, this transportation capacity provides assurance that our natural gas will not be shut in, which can result from 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

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

In December 2005, the FERC released its first case-specific review of the income tax allowance issue reaffirming its income tax allowance policy and directing the pipeline to provide certain evidence necessary to determine its income tax allowance. The FERC's *BP West Coast* remand decision and the new tax allowance policy were appealed to the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit Court.

In May 2007, the D.C. Circuit Court upheld the income tax allowance policy adopted by the FERC for master limited partnerships ("MLPs") and other non-taxable entities. On the basis of the Santa Fe Pacific Pipeline, L.P. ("SFPP") order, the D.C. Circuit Court concluded that the FERC's new policy statement applied to SFPP and resolved the principal defect of the Lakehead policy, which was the inadequately explained differential treatment of the tax liability of the individual and corporate partners. On that basis, the D.C. Circuit Court affirmed the FERC's tax allowance policy as being reasonable and in accordance with the FERC's statutory discretion. As such, the D.C. Circuit Court affirmed that an allowance should be permitted on all partnership interests, or similar legal interest, if the owner of that interest has an actual or potential income tax liability on the public utility income earned though the interest. We believe that all applicable assets will be entitled to a tax allowance to the extent a pipeline's partners have income tax liability on the income they receive from the pipeline. In August 2007, the D.C. Circuit Court denied a request for rehearing of its May 2007 decision, and the decision is now final and cannot be appealed.

FERC Return on Equity Policy for Oil Pipelines

On April 17, 2008, the FERC issued a Policy Statement regarding the inclusion of MLPs in the proxy groups used to determine the return on equity ("ROE") for oil pipelines. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity,* 123 FERC ¶ 61,048 (2008), *rehearing denied,* 123 FERC ¶

61,259 (2008). No petitions for review of the Policy Statement were filed with the D.C. Circuit Court. The Policy Statement largely upheld the prior method by which ROEs were calculated for oil pipelines, explaining that MLPs should continue to be included in the ROE proxy group for oil pipelines, and that there should be no ceiling on the level of distributions included in the FERC's current Discounted Cash Flow ("DCF") methodology. The Policy Statement further indicated that the Institutional Brokers Estimated System ("IBES") forecasts should remain the basis for the short-term growth forecast used in the DCF calculation and there should be no modification to the current respective two-thirds and one-third weightings of the short- and long-term growth factors. The primary change to the prior ROE methodology was the Policy Statement's holding that the gross domestic product ("GDP") forecast used for the long-term growth rate should be reduced by 50 percent for all MLPs included in the proxy group. Everything else being equal, that change will result in somewhat lower ROEs for oil pipelines than would have been calculated under the prior ROE methodology. The actual ROEs to be calculated under the new Policy Statement, however, are dependent on the companies included in the proxy group and the specific conditions existing at the time the ROE is calculated in each case.

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 took effect 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. In January 2006, we began expensing all first-time internal inspection costs for all our pipeline systems, whether or not they are subject to the FERC's regulation, on a prospective basis. We will continue to expense secondary internal inspection tests consistent with the previous practice. Refer to Note 2—Summary of Significant Accounting Policies included in our consolidated financial statements beginning at page F-1 of this annual report on Form 10-K for additional discussion.

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

Our Lakehead, North Dakota, and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act ("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 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 can charge for service on interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" as well as nondiscriminatory. The ICA permits interested parties 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 the FERC finds the new or changed rate 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.

In October 1992, Congress passed the Energy Policy Act of 1992 ("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 determined our 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 our North Dakota and Ozark systems should be found to be 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 adopted an indexing rate methodology for petroleum pipelines. Under these 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 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 equal to the annual change in the Producer Price Index for Finished Goods, or PPI-FG, minus one percentage point. The index was subject to review every five years. Rates were then subject to an annual adjustment, based upon changes in the PPI-FG minus 1%, in order to accurately reflect the actual cost changes experienced by the oil pipeline industry. In December 2000, as part of the FERC’s five-year review of the oil-pricing index (July 2001 through June 2006), the FERC concluded that the PPI-FG accurately reflected the actual cost changes experienced by the industry. In February 2003, the FERC issued an Order on Remand, concluding that for the current five-year period, the oil-pricing index should be the PPI-FG. In order to calculate the 2003 ceiling rate levels, oil pipelines were permitted to use the PPI-FG adjustment as though it had been in effect since 2001. As of July 1, 2008, the index was equal to PPI-FG plus 1.3 percentage points, resulting in an index of 5.1653% for the period of July 1, 2008 through June 30, 2009.

Regulation by the FERC of Interstate Natural Gas Pipelines

Our AlaTenn, Midla and UTOS systems are interstate natural gas pipelines regulated by the FERC under the Natural Gas Act, or NGA, and the Natural Gas Policy Act, or NGPA. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides service to its customers. Rates charged by natural gas companies must be determined by the FERC to be just and reasonable. 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;
- terms and conditions of services and service contracts with customers;

- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

The maximum recourse rates that may be charged by our pipelines for their services are established through the FERC's ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's actual prudent historical cost investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC approved tariff. Rate design and the allocation of costs also can impact a pipeline's profitability. Our interstate pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not "unduly discriminate."

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 pipeline 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 is just and reasonable as required by the NGA, the FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, 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 beyond the date on which the change would otherwise go into effect 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.

On December 21, 2007, the FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. On November 20, 2008, FERC issued Order 720, which requires interstate pipelines to post information concerning daily actual flows of no notice service, commencing January 31, 2009. Order 720 also requires non-interstate pipelines that deliver more than 50 million MMBtu per year to post daily on an Internet website and in FERC-prescribed formats certain information concerning receipt and delivery point capacity and scheduled volumes. This requirement is effective 150 days following the FERC issuance of an order on the pending requests for rehearing. Because requests for rehearing are pending, the final rules remain subject to change. Adoption of this proposal by the FERC will result in additional administrative burdens and will likely result in increased capital costs.

In addition, on November 20, 2008, the FERC issued a notice of inquiry ("NOI") seeking comment on whether it should impose additional reporting requirements on intrastate pipelines providing service under Section 311 of the NGPA, such as our East Texas system. In particular, the FERC seeks comment on whether it should require such pipelines to post the details of their transactions with shippers in a manner more comparable to the requirements applicable to interstate pipelines. FERC has not yet taken any further action on this NOI, and we cannot at this stage predict what, if any, additional reporting requirements may be adopted.

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 potential market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005 ("EPAct 2005"), and the FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPAct 2005 prohibits the use of any "manipulative or deceptive device or contrivance" in connection with the purchase or sale of natural gas, electric energy or transportation subject to the FERC's jurisdiction. The FERC then adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPAct 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are very vague and subject to broad interpretation. Only two orders interpreting these rules have been issued to date, and each of these is subject to further proceedings. These orders reflect the FERC's view that it has broad latitude in determining whether specific behavior violates the rules. In addition, EPAct 2005 gave the FERC increased penalty authority for these violations. The FERC may now issue civil penalties of up to $1 million per day for each violation of the FERC's rules, and there are possible criminal penalties of up to $1 million and 5 years in prison. Given the FERC's broad mandate granted in EPAct 2005, it is assumed that, if energy prices are high or exhibit what the FERC deems to be "unusual" trading patterns, the FERC will investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

Also, in December, 2007, the FERC issued new rules (Order 704) requiring that any market participant, including intrastate pipelines and marketers, such as Enbridge Marketing (US) L.P., that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year, must annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and detecting market manipulation. The FERC issued an order on rehearing of these rules on September 18, 2008, which largely retained the existing rules, except that the FERC exempted certain types of purchases and sales, such as those involving unprocessed gas and bundled retail sales pursuant to state regulated tariffs, and clarified that other end-use purchases and sales are not exempt from the reporting requirements. Adoption of these rules will result in increased administrative burdens and may also increase capital costs.

Other than the market manipulation and transparency rules described above, our Texas intrastate pipelines are generally not subject to regulation by the FERC. However, to the extent our intrastate pipelines transport natural gas in interstate commerce, the rates, terms and conditions of such transportation are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"). In addition, some of our operations are subject to regulation under the Texas Utilities Code, as implemented by the Texas Railroad Commission ("TRRC"). Generally, the TRRC is vested with authority to ensure that rates charged for natural gas sales and transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law, unless challenged in a complaint. We cannot predict whether such a complaint may be filed against us or whether the TRRC will change its method of regulating rates.

During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 ("Competition Bill") and H.B. 1920 ("LUG Bill"). The Competition Bill gives the TRRC the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. The Competition Bill also gives the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the TRRC with procedures unique to lost and unaccounted for gas issues. The LUG Bill also extends the types of information that can be requested, provides producers with an annual audit right, and provides the TRRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007.

Proposals are pending in the 2009 session of the Texas legislature which, if enacted, could give the TRRC or other governmental authorities greater authority over the siting and operation of intrastate pipelines and appurtenant facilities. We cannot predict whether or not this, or other legislation affecting intrastate pipeline operations, may be enacted during such legislative session, and if so, how any such new legislation might affect our operations. We do not anticipate our operations would be affected differently from those of other intrastate pipeline and gathering companies.

Intrastate Pipeline Regulation

Our intrastate liquids and natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Various state agencies possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Additionally, some state agencies have the authority to regulate transportation rates, service terms and conditions, and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies do not discriminate amongst similarly situated customers.

Enbridge's intrastate pipeline operations are also subject to limited regulation by the FERC under Section 311 of the NGPA, i.e., to the extent such operations include the delivery of natural gas into interstate commerce, and under Section 23 of the NGA, which the U.S. Congress added to the NGA by the EPAct 2005. Under Section 311 of the NGPA, an intrastate natural gas pipeline may make deliveries into interstate commerce subject to the FERC's jurisdiction over the rates, terms and conditions of such transportation services. Additionally, on September 19, 2008, the FERC issued Order No. 714, which requires that all tariffs, tariff revisions and rate change applications be filed electronically according to a set of standards that are applicable to all such documents, including Statements of Operating Conditions and rate applications filed pursuant to Section 311. Although regulatory guidance regarding the exact requirements of Order No. 714 has been less than definite, Enbridge is proceeding in a prudent manner and reasonably foresees complete and timely compliance with all Order No. 714 requirements.

Under Section 23 of the NGA, the FERC recently promulgated new rules, Orders No. 704-A and No. 720, to facilitate one of the stated goals of EPAct 2005, i.e., to enhance the transparency of the U.S. natural gas market. Order No. 704-A, issued September 18, 2008, mandates the annual report of transactional information by wholesale natural gas buyers and sellers who buy or sell greater than 2.2 million MMBtu in a reporting year. Because our gathering and processing operations frequently include natural gas purchases and sales, the annual sum of which are likely to be greater than 2.2 million MMBtu, we anticipate being subject to this reporting requirement every year on an on-going basis. Order No. 720, issued November 20, 2008, requires "major non-interstate pipelines"—defined as pipelines that deliver more than 50 million MMBtu per year—to post on their internet websites information regarding the daily scheduled volume and design capacity for certain receipt and delivery points. Enbridge considers it prudent to duly comply with the Order until such time as it may be vacated by a court of competent jurisdiction and is, therefore, making preparations to do all internet postings as required.

Notwithstanding that the FERC's newly-adopted Orders No. 714, No. 704-A, and No. 720 increase certain of our administrative obligations, Enbridge believes that these regulatory changes will have little or no adverse impact on our day to day operations.

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 FERC jurisdiction. However, as noted in *Intrastate Pipeline Regulation*, above, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, will be subject to FERC Order 704-A. Additionally, if one of our gathering systems were to fall under the definition of "major non-interstate pipeline," such gatherer would be subject to FERC Order No. 720, as described in *Intrastate Pipeline Regulation* above, subject to a court ruling otherwise. State regulations of gathering facilities typically address the safety and environmental concerns involved in the design, construction, installation, testing and operation of gathering facilities, as well as, in some circumstances, nondiscriminatory take requirements, but historically has not entailed rate regulation. In 2005, the FERC initiated an inquiry regarding the extent to which gathering systems (both offshore and onshore), particularly those that had been previously transferred from a regulated entity, should be regulated by the FERC.

The FERC terminated this inquiry in early 2007 without making any finding that would expand its existing regulatory purview over gathering facilities. Further, some states have, or are considering providing, greater regulatory scrutiny over the commercial regulation of the 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 or perceived rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to significant and unduly burdensome state or federal regulation of rates and services.

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. On December 26, 2007, the FERC issued Order No. 704, a Final Rule which adopted new regulations designed to facilitate price transparency in markets for the wholesale sale of physical natural gas in interstate commerce pursuant to the FERC's authority under Section 23 of the Natural Gas Act. The regulations adopted in Order No. 704 require most natural gas market participants to file Form No. 552, a new annual report on wholesale, physical natural gas sales and purchases during the previous calendar year. On September 18, 2008, the FERC issued Order No. 704-A, an order on rehearing and clarification of Order No. 704. In Order No. 704-A, FERC largely affirmed the basic determinations reached in Order No. 704 and also granted rehearing in part and clarification of certain aspects of Order No. 704.

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 Transportation Rate Cases

Lakehead system

Under published tariffs as of December 31, 2008 (including the transportation rate surcharges related to Lakehead system expansions) for transportation on our Lakehead system, the rates for transportation of heavy crude oil from the International Board near Neche, where the System enters the United States (unless otherwise stated), to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel
To Clearbrook, Minnesota	$0.3076
To Superior, Wisconsin	0.6400
To Chicago, Illinois area	1.3938
To Marysville, Michigan area	1.6777
To Buffalo, New York area	1.7186
Chicago to the international border near Marysville	0.5744

The transportation rates as of December 31, 2008 for light and medium crude oil and NGLs are lower than the transportation rates set forth in this table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. Lakehead periodically adjusts transportation rates as allowed under the FERC's indexing methodology and the tariff agreements described below:

Base Rates

The base portion of the transportation rates for our Lakehead system are subject to an annual adjustment, which cannot exceed established ceiling rates as approved by the FERC, and are determined in compliance with the FERC approved indexing methodology.

SEP II Surcharge

Under the Settlement Agreement with CAPP that the FERC approved in 1996 and reconfirmed in 1998, Lakehead implemented a transportation rate surcharge related to the SEP II project. This surcharge, which is added to the base transportation rates, is a cost-of-service based calculation that is trued-up annually (usually in April) for actual costs and throughput from the previous calendar year, and is not subject to indexing. The initial term of the SEP II portion of the settlement agreement was for 15 years, beginning in 1999.

Terrace Surcharge

Under the Tariff Agreement approved by the FERC in 1998, Lakehead also implemented a transportation rate 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 Lakehead and Enbridge Pipelines Inc., Lakehead's share of the surcharge was increased to $0.026 per barrel. This surcharge was in effect until April 1, 2004, when Lakehead's share of the surcharge changed to $0.007 per barrel. Lakehead's share will remain at this level until 2010, at which time the surcharge will return to $0.013 per barrel through 2013, when the agreement expires. In addition to the Terrace surcharge, included in the 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 is less than 225,000 m^3 per day, an adjustment is made to the Terrace surcharge. In 2008, this adjustment was $0.05 per barrel, based on annual actual average pumping exiting Clearbrook of 202,900 m^3 per day in 2007.

Facilities Surcharge

On July 1, 2004, the FERC approved a settlement with CAPP involving a Facilities Surcharge Mechanism ("FSM"), which allows for recovery of costs for enhancements or modifications to the system at shipper request and approved by CAPP. The Facilities Surcharge permits our Lakehead system to recover the costs associated with particular shipper requested projects through an incremental surcharge layered on top of the existing base transportation rates and other FERC-approved surcharges already in effect. Like the SEP II surcharge, the Facilities Surcharge is a cost-of-service based mechanism that is trued-up each year for actual costs and throughput and, therefore, is not subject to adjustment under indexing. In 2008, the Facilities Surcharge was $0.322 per barrel for light crude movements from the international border near Neche to Chicago. There were four facilities added to the FSM on February 29, 2008 (Docket No. OR08-10-000): Project 5 (Southern Access Expansion Project); Project 6 (Tank 34 at Superior Terminal and Tank 79 at Griffith Terminal); Project 7 (Clearbrook Manifold); and Project 8 (Tank 35 at Superior Terminal and Tank 80 at Griffith Terminal). These projects were incorporated into the FSM, which initially included four facilities, as the result of negotiations between management and CAPP.

Project 5 relates to the Southern Access Mainline Expansion Project ("SA Expansion"). The FERC approved the Offer of Settlement on March 16, 2006, which sought approval for the SA Expansion surcharge under the provisions of the previously approved FSM. The SA Expansion involves the construction of a new 42-inch diameter pipeline between Superior and Flanagan, along with associated upstream modifications to balance the expanded capacity created by the new Superior-to-Flanagan line. Stage 1 of the expansion program (the build from Superior to Delavan) was included in the FSM effective April 1, 2008.

The Alberta Clipper project is a new crude oil pipeline from Hardisty to Superior (approximately 990 miles). On both sides of the border, the system will initially be able to transport an additional 450,000 Bpd with the potential for expansion up to 800,000 Bpd. The U.S. portion of the project includes approximately 325 miles of new 36-inch pipeline between the International Border near Neche and Superior, along with three new pump stations at existing pump locations and five 250,000-barrel breakout tanks at Superior. The estimated cost of the U.S. portion to be recovered through the FSM is approximately $1.2 billion in 2008 U.S. dollars. FERC approved the Settlement by letter dated August 28, 2008 and construction on the U.S. side will begin in June 2009. The entire project is to be completed and placed in service in the first six months of 2010.

Mid-Continent system (Ozark)

Our Mid-Continent system is comprised of pipeline, terminaling, and storage infrastructure located in the mid-continent region of the United States. Specifically, the system originates in Cushing and offers transportation service to Wood River, West Tulsa, other Mid-Continent system facilities, local area refineries, and other interconnected non-affiliated pipelines. Transportation rates for light crude oil from Cushing to principle delivery points are set forth below:

	Published Transportation Rate Per Barrel
To Wood River, Illinois	$0.4824
To West Tulsa, Oklahoma	0.2025

The transportation rates as of December 31, 2008, outlined above, apply to light crude only. Medium and heavy crude oil transportation rates on these systems are higher to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. In addition to the routes above, our Mid-Continent system also has the following two joint tariffs—one with All American Pipeline, L.P., which allows for transportation from points in Texas and Jal, New Mexico, to Wood River, and another with Koch Pipeline Company, L.P., which allows for transportation from Cushing to Hartford Tankage, Illinois.

Where applicable, transportation rates are periodically adjusted as allowed under the FERC's indexing methodology. Currently, this methodology allows for an adjustment of transportation rates effective July 1 of each year.

Enbridge North Dakota system

The Enbridge North Dakota system consists of both gathering and trunk line assets. All gathering rates in effect as of December 31, 2008, from points in North Dakota and Montana, are $0.6678 per barrel. Effective

January 1, 2008, two new surcharges were implemented as a part of the Phase V Expansion program. In August 2006, the Enbridge North Dakota system submitted an Offer of Settlement to the FERC for an expansion of the system, which was approved by the Commission on October 31, 2006 (Docket No. OR06-9-000). The Offer of Settlement included mainline expansion and looping surcharges determined on a cost of service basis and are trued-up each year to actual costs and volumes, and are not subject to the FERC indexing methodology. These surcharges are applicable for the five years immediately following the in-service date of the Phase V Expansion program, which was placed in service in January 2008. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originating at Trenton and Alexander, North Dakota. The rates and surcharges for transportation of light crude oil to principle delivery points via trunk lines on the Enbridge North Dakota System are set forth below:

	Indexed Base Rate per Barrel	Phase V Surcharge Per Barrel	Published Rate per Barrel FERC No. 55 [1]
From Glenburn, Haas, Lignite, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$0.8120	$0.1434	$0.9554
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	0.9298	0.1434	1.0732
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to to Clearbrook, Minnesota	0.9558	0.1434	1.0992
From Tioga, North Dakota to Clearbrook, Minnesota	0.8379	0.1434	0.9813
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	1.0609	0.6170	1.6779
From Alexander, North Dakota to Clearbrook, Minnesota	1.1000	0.6170	1.7170
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5108	—	0.5108
From Reserve, Montana to Tioga, North Dakota	0.5762	—	0.5762
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	0.4847	0.4736	0.9583
From Alexander, North Dakota to Clearbrook, Minnesota	0.5235	0.4736	0.9971

(1) Pursuant to FERC Tariff No. 55 as filed with the FERC on May 30, 2008, with an effective date of July 1, 2008.

On January 18, 2008, Enbridge North Dakota submitted an Offer of Settlement to the FERC to facilitate a further expansion of our North Dakota system. The Phase VI Expansion program is expected to add approximately 40,000 Bpd of capacity into Minot, North Dakota from the western end of the pipeline system and approximately 51,000 Bpd of capacity from Minot to the eastern end of the system at Clearbook. Under the terms of the settlement, which was approved by the FERC on October 20, 2008 (Docket No. OR08-6-000), expansion costs will be recovered through a cost-of-service based surcharge on all shipments to Clearbrook. The surcharge will be trued-up on an annual basis to actual costs and volumes, and will be added to existing base rates and other previously approved surcharges, for a period of seven years. The Phase VI Expansion program capital cost will be approximately $150 million and will increase the maximum average capacity of the system to about 161,000 Bpd in 2010.

Natural Gas Systems

Tariff rates on the FERC-regulated natural gas pipelines are approved by the FERC and vary by pipeline depending on a number of factors, including cost of providing service, throughput levels on the pipeline, and other factors. Competitive forces may prompt us to charge tariff rates below the FERC-approved maximum 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 United States Department of Transportation, or DOT, Pipeline and Hazardous Materials Safety Administration ("PHMSA") under Title 49 United States Code of Federal Regulations (Pipeline Safety Act, or PSA) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. The PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including intrastate pipelines. 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.

In 1999 PHMSA published a final rule regarding the qualification of pipeline operations personnel. The "Operator Qualification" regulations require pipeline operators to utilize qualified individuals to perform pipeline operations and maintenance activities or tasks. The rule required pipeline operators to have a written plan in place by April 27, 2001 and to complete qualification of personnel by October 28, 2002. We have prepared an Operator Qualification Plan which is in compliance with the final rule. The implementation of this plan does not have a material affect on the operations of our pipelines.

On December 17, 2002, the PSI Act of 2002 was enacted reauthorizing and amending the PSA. The most significant amendment required natural gas pipelines to develop integrity management programs and conduct integrity assessment tests at a minimum of seven year intervals. Such tests can include internal inspection, hydrostatic pressure tests or direct assessments on pipelines in certain high consequence areas. The PHMSA has since promulgated rules for this and other mandates included in the PSI Act of 2002.

On December 29, 2006, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES of 2006") was enacted, which further amended the Pipeline Safety Act. Many of the provisions were welcome, including strengthening excavation damage prevention and enforcement. The most significant provisions of PIPES of 2006 that will affect us, but not materially, include a mandate to PHMSA to remove most exemptions from federal regulations for liquid pipelines operating at low stress and mandates PHMSA to undertake rulemaking requiring pipeline operators to have a human factors management plan for pipeline control room personnel, including consideration for controlling hours of service.

We have incorporated the new requirements of the 2002 and 2006 PSA amendments into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material.

The Pipeline Safety Act Reauthorization of 2006 ("PIPES Act") required, among other measures, for PHMSA to extend their current jurisdictional authority to regulate previously exempted low operating stress pipelines. In September 2007, the PHMSA issued a NOPR that details how such low stress pipelines would be regulated and the safety measures that would be required. Industry commented and PHMSA issued the Final Rule on June 3, 2008. The Final Rule does not have any regulatory requirements that materially affect our low stress transmission pipelines.

When hydrocarbons are released into the environment, the PHMSA can impose a return-to-service plan, which can include implementing certain internal inspections, pipeline pressure reductions, and other strategies to verify the integrity of the pipeline in the affected area. We do not anticipate any return-to-service plans that will have a material impact on system throughput or compliance costs; however, we have the potential of incurring expenditures to remediate any condition in the event of a discharge or failure on our systems.

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.

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, or CAA, and the federal Clean Water Act, or CWA, 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.

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 Environmental Protection Agency, or EPA. We believe we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The federal Comprehensive Environmental Response, Compensation, and Liability Act, or 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 Occupational Safety and Health Administration, or 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 OSHA 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, Resource Conservation & Recovery Act 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.

EMPLOYEES

Neither we nor Enbridge Management have 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. The coverage limits and deductible amounts at December 31, 2008 for our insurance policies denominated in CAD and United States dollars ("USD") were as follows:

	Coverage Limits		Deductible Amount	
Insurance Type	CAD	USD[1]	CAD	USD[1]
		(in millions)		
Property and business interruption	Up to $400.0 to $700.0	Up to $326.6 to $571.6	$10.0	$8.2
General liability	Up to $400.0 to $650.0	Up to $326.6 to $530.8	0.1	0.1
Pollution liability	Up to $400.0 to $650.0	Up to $326.6 to $530.8	5.0	4.1

(1) Based on an exchange rate at December 31, 2008 of $1.2246 CAD to $1 USD.

We can make no assurance that the 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.

TAXATION

We are not a taxable entity for U.S. federal income tax purposes. Generally, federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. In a limited number of states, an income tax is imposed upon us and generally, not our individual partners. The income tax that we bear is reflected in our consolidated financial statements. The allocation of taxable income to our individual partners 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 Securities and Exchange Commission, or SEC, under the Securities Exchange Act of 1934, as amended, which we refer to as 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 at *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 make available free of charge on or through our Internet website *http://www.enbridgepartners.com* our Annual Reports 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 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 maintain or increase cash distributions.

Our strategy contemplates significant expenditures for the development, construction or other acquisition 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. Additionally, the construction of new assets involves numerous regulatory, environmental, legal, political and operational risks that are difficult to predict and beyond our control. 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 equity.

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

Our ability to access the credit and capital markets on attractive terms to obtain funding for our capital projects may be limited due to the deterioration of these markets.

We expect to make significant expenditures for the construction of additional crude oil transportation infrastructure over the next two years. Our ability to fund these expenditures is dependent on our ability to access the capital necessary to finance the construction of these facilities. Domestic and global financial markets and economic conditions have been, and continue to be, weak and volatile and have contributed significantly to a substantial deterioration in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and the re-pricing of credit risks have made, and likely will continue to make, it difficult to obtain funding for our capital needs from the credit and capital markets on terms similar to our recent capital-raising transactions. As a result, we may revise the timing and scope of these projects as necessary to adapt to existing markets and economic conditions.

In particular, the cost of raising funds in the debt and equity capital markets has increased while the availability of funds from those markets has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining funds from the credit markets has increased as many lenders have increased interest rates, enacted tighter lending standards and reduced, and in some cases ceased to provide, funding to borrowers.

Due to the recent downturn in the financial markets, including the issues surrounding the solvency of many financial institutions and the recent failure, combinations and announced combinations of several financial institutions, our ability to obtain capital from our Credit Facility may be impaired. For example, since Lehman Brothers Holdings Inc. ("Lehman") filed a petition under Chapter 11 of the U.S. Bankruptcy Code, Lehman Brothers Bank FSB ("Lehman BB"), a subsidiary of Lehman and a committed lender under our Credit Facility, has declined requests to honor its commitment to lend up to $82.5 million under our Credit Facility, effectively reducing the amount available to us under our Credit Facility to $1,167.5 million. We may be unable to use the full borrowing capacity under our Credit Facility if other lenders do not replace Lehman BB's funding commitment under the Credit Facility or if any of the remaining committed lenders is unable or unwilling to fund its portion of any funding request we make under our Credit Facility.

Due to these factors, we cannot be certain that funding for our capital needs will be available from the credit and capital markets if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions and construction projects, otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

A downgrade in our credit rating could require us to provide collateral for our hedging liabilities and negatively impact our borrowing capacity under our Credit Facility.

Standard & Poor's (S&P) and Moody's Investors Service (Moody's) rate our non-credit enhanced, senior unsecured debt at "BBB" with a negative outlook and "Baa2" with a negative outlook, respectively. Although we are not aware of any current plans by S&P or Moody's to lower their respective ratings on such debt, we cannot be assured that such credit ratings will not be downgraded.

Currently, we are parties to certain International Swap and Derivative Association, Inc., or ISDA®, agreements associated with the derivative financial instruments we use to manage our exposure to fluctuations in commodity prices. These ISDA® agreements require us to provide assurances of performance if our counterparties' exposure to us exceeds certain levels or thresholds. We generally provide letters of credit to satisfy such requirements. At December 31, 2008, we were not required to provide any assurances of performance for our then outstanding derivative financial instruments. If our credit ratings had declined to BBB- for S&P or Baa3 for Moody's, at December 31, 2008, we would have been required to provide letters of credit in the aggregate amount of $51.7 million to satisfy this requirement of our ISDA® agreements. The amount of any letters of credit we would have to establish under the terms of our ISDA® agreements would reduce the amount that we are able to borrow under our Credit Facility.

We may not have sufficient cash flows to enable us to continue to pay distributions at the current level.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay distributions at the current level. The amount of cash we are able to distribute depends on the amount of cash we generate from our operations, which can fluctuate quarterly based upon a number of factors. The amount of cash available for distribution also will depend on other factors, including:

- the level of capital expenditures we make;
- the amount of cash reserves established by Enbridge Management;
- our ability to access capital markets and borrow money;
- our debt service requirements and restrictions in our credit agreements;
- fluctuations in our working capital needs; and
- the cost of acquisitions.

In addition, unitholders should note that the amount of cash we distribute depends primarily on our cash flow rather than net income or net loss. Therefore, we may make cash distributions during periods when we record net losses or may make no distributions during periods when we record net income.

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;
- a decrease in liquidity as a result of utilizing significant amounts of available cash or borrowing capacity to finance an acquisition;
- the loss of critical customers or employees at the acquired business;
- the assumption of unknown liabilities for which we are not fully and adequately indemnified;
- 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 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 can directly and adversely affect our revenues and results of operations. The volume transported on our pipelines can be influenced by factors beyond our control including:

- competition;
- regulatory action;
- weather conditions
- storage levels;
- alternative energy sources;
- decreased demand;
- fluctuations in energy commodity prices;
- economic conditions;
- supply disruptions;
- availability of supply connected to our pipeline systems; and
- availability and adequacy of infrastructure to move supply into and out of our systems.

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. Decreases in conventional crude oil exploration and production activities in western Canada and other factors, including supply disruption, higher development costs and competition, can slow the rate of growth of our Lakehead system. The volume of crude oil that we transport on our Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the volumes of crude oil and refined products delivered by others 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 our 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. Full utilization of additional capacity as a result of our current and future expansions of our Lakehead system, including the Southern Access project, will largely depend on these anticipated increases in crude oil production from oil sands projects. A reduction in demand for crude oil or a decline in crude oil prices may make certain oil sands projects uneconomic since development costs for production of crude oil from oil sands is greater than development costs for production of conventional crude oil. Crude oil prices remain volatile and have declined significantly in recent months. Oil sands producers may cancel or delay plans to expand their facilities, as some oil sands producers have already done, if crude oil prices remain at current levels or decline further. Additionally, measures adopted by the government of the Province of Alberta to increase its share of revenues from oil sands development coupled with the decline in crude oil prices could reduce the volume growth we have anticipated in executing our construction projects to increase the capacity of our crude oil pipelines.

The volume of shipments on natural gas and NGL systems depends on the supply of natural gas and NGLs available for shipment from the producing regions that supply these systems. Supply available for shipment can be affected by many factors, including commodity prices, weather and drilling activity. 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 for a variety of reasons, including a decline in the availability of natural gas from our Mid-continent, U.S. Gulf Coast and East Texas producing regions, or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by the natural gas systems were 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.

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 our 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 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. A number of new interstate natural gas transmission pipelines being constructed could reduce the revenue we derive from the interstate and intrastate transmission of natural gas. 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. Our Midla system has recently negotiated the renewal of a contract with one of its primary customers. Other systems such as our AlaTenn system face similar competition for customers. 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.

Our gas marketing operations involve market and 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, limitations 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.

The prices of natural gas, NGLs and crude oil are inherently volatile and we expect this volatility will continue. We buy and sell natural gas and NGLs in connection with our marketing activities. Our exposure to commodity price volatility is inherent to our natural gas and NGL purchase and resale activities, in addition to our natural gas processing activities. 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. However, because we are not fully hedged, we will continue to have commodity price exposure on the unhedged portion of the fees we derive from the commodities we receive in-kind as payment for our gathering, processing, treating and transportation services. We are exposed to fluctuations in commodity prices on 20 to 40 percent of the natural gas and NGLs we expect to receive in the near term. As a result of this unhedged exposure, a substantial decline in the prices of these commodities could adversely affect our financial performance.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. Our hedging activities can result in substantial losses if hedging arrangements are imperfect or ineffective and our hedging policies and procedures are not followed properly or do not work as intended. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. 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 earnings volatility due to fluctuations in commodity prices.

Changes in, or challenges to, our rates could have a material adverse effect on our financial condition and results of operations.

The rates charged by several of our pipeline systems are regulated by the FERC or state regulatory agencies or both. 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 would 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 implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services. Some producing states, including Oklahoma and Texas, are considering legislation that would require rate and/or service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

We believe that the rates we charge for transportation services on our interstate common carrier oil and open access natural gas pipelines are just and reasonable under the ICA and NGA, respectively. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, or a regulator's own initiative, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier oil and open access natural gas 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.

Increased regulation and regulatory scrutiny may reduce our revenues

Our interstate pipelines and certain activities of our intrastate natural gas pipelines are subject to FERC regulation of terms and conditions of service. In the case of interstate natural gas pipelines, FERC also establishes requirements respecting the construction and abandonment of pipeline facilities. FERC has pending proposals to increase posting and other compliance requirements applicable to natural gas markets, and in 2008, has continued to step up its enforcement efforts. The new political administration is focused on energy policy and has the authority to name new FERC commissioners, including a Chairman, to reflect a Democratic majority. Such changes could prompt an increase in FERC regulatory oversight of our pipelines and additional legislation that could increase our FERC regulatory compliance costs and decrease the net income generated by our pipeline systems.

Compliance with environmental and operational safety regulations may expose us to significant costs and liabilities.

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. Numerous governmental authorities have the power to enforce compliance with the laws and regulations they administer and permits they issue, oftentimes requiring difficult and costly actions. Our failure to comply with these laws, regulations and operating permits can result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. Our operation of liquid petroleum and natural gas gathering, processing, treating and transportation facilities exposes us to the risk of incurring significant environmental costs and liabilities. Additionally, operational modifications necessary to comply with regulatory requirements and resulting from our handling of liquid petroleum and natural gas, historical environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents can also result in significant cost. We may incur joint and several strict liability under these environmental laws and regulations in connection with discharges or releases of liquid petroleum and natural gas and wastes on, under or from our properties and facilities, many of which have been used for gathering or processing activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of properties through which our gathering systems pass and facilities where our liquid petroleum and natural gas or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may also incur costs in the future due to changes in environmental and safety laws and regulations, or re-interpretations of enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher rates.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Canada is one of many foreign nations participating in the Kyoto Protocol, a treaty designed to reduce greenhouse gas emissions. The treaty requires Canada to reduce greenhouse gas emissions to 6% below 1990 levels by 2012. While the United States is not a signatory to the Kyoto Protocol, its Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in *Massachusetts, et al. v. EPA,* held that carbon dioxide may be regulated as and "air pollutant" under the federal Clean Air Act. In July 2008, the EPA released an *Advanced Notice of Proposed Rulemaking* regarding possible future regulation of greenhouse gas emissions under the Clean Air Act and other potential methods of regulating greenhouse gases. Although it is not possible at this time to predict how legislation or new regulation that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for our services.

Pipeline operations involve numerous risks that 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. 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. These types of catastrophic events could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, any of which could also result in substantial losses for which we may bear a part or all of the cost. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these catastrophic events could be greater.

Measurement adjustments on our pipeline system can be materially impacted by changes in estimation, commodity prices and other factors.

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum pipelines. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- Degradation, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments is inherently difficult because physical measurements of volumes are not practical as products continuously move through our pipelines and virtually all of our pipeline systems are located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the length of our pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

Natural gas measurement adjustments occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement adjustments is complicated by several factors including: (1) the significant quantities (i.e., thousands) of measurement meters that we use throughout our natural gas systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas in the streams gathered and processed through our systems; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our natural gas systems.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

Some of our customers may experience financial problems that could have a significant affect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. The market capitalizations of many of our customers have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE AND RELATIONSHIPS WITH OUR GENERAL PARTNER AND ENBRIDGE MANAGEMENT

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

Enbridge indirectly owns all of the shares of our general partner and all of the voting shares 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 delegate, 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 rely on employees of Enbridge, and its affiliates, who act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our general partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our general partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our general partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our general partner. For example, our partnership agreement:

- permits our general partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;

- provides that any standard of care and duty imposed on our general partner will be modified, waived or limited as required to permit our general partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the general partner to be in our best interests; and
- provides that our general partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our general partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our general partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our general partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge will pursue certain acquisitions or other business opportunities;
- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;
- whether Enbridge Management will issue additional shares;
- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;
- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our general partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us, that are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant 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 business that materially and directly competes with us 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 business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue 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.

These exceptions 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.

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 and the issuance of additional Class C units, 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 or Class C 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 or Class C units currently held by our general partner could absorb some of the trading market demand for the outstanding Class A common units.

The Class A common units issuable upon conversion of our Class C units may be sold in the public or private markets, which could have an adverse impact on the trading price of our Class A common units.

As of February 19, 2009, we had approximately 20,313,522 Class C units outstanding, which will convert into Class A common units on a one-for-one basis on August 15, 2009, subject to the satisfaction of certain conditions. The sale of any of these Class A common units in the public or private markets could have an adverse impact on the trading price of our Class A common units.

Holders of our limited partner interests have limited voting rights

Our unitholders have limited voting rights on matters affecting our business, which may have a negative effect on the price at which our common units trade. In particular, the unitholders did not elect our general partner or the directors of our general partner or Enbridge Management and have no rights to elect our general partner or the directors of our general partner or Enbridge Management on an annual or other continuing basis. Furthermore, if unitholders are not satisfied with the performance of our general partner, they may find it difficult to remove our general partner. Under the provisions of our partnership agreement, our general partner may be removed upon the vote of at least 66 2/3% of the outstanding common units and Class C units voting together as a class (excluding the units held by the general partner and its affiliates) and a majority of the outstanding i-units voting together as a separate class (excluding the number of i-units corresponding to the number of shares of Enbridge Management held by our general partner and its affiliates). Such removal must, however, provide for the election and succession of a new general partner, who may be required to purchase the departing general partner interest in us in order to become the successor general partner. Such restrictions may limit the flexibility of the limited partners in removing our general partner, and removal may also result in the general partner interest in us held by the departing general partner being converted into 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 any of our subsidiaries that are 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, and 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 MAKE DISTRIBUTIONS

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 most significant operating subsidiary is restricted by its First Mortgage Notes from making distributions to us, other than in additional partnership interests in it, unless (1) the distribution is in cash, (2) the distribution amount does not exceed the current available cash of that subsidiary, (3) a default does not exist under the First Mortgage Notes immediately after giving effect to the distribution and (4) timely notice of the distribution has been give to the holders of the First Mortgage Notes. In addition, we are prohibited from making distributions to our unitholders during (1) the existence of certain defaults under our Credit Facility or (2) during a period in which we have elected to defer interest payments on the Junior Notes, subject to limited exceptions as set forth in the related indenture. Further, 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 all or substantially all of our assets, to incur liens to secure debt and to enter into sale and leaseback transactions. 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 our 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 could 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, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation similar to recent tax legislation in Texas and Michigan. State tax legislation resulting in the imposition of a partnership-level income tax on us could reduce the cash distributions we make on the Class A and B common units and the number of i-units and Class C units that we will distribute quarterly. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our Class A common 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, 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. 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.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Class A Common Units.

When we issue additional Class A Common Units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of Class A Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We treat each purchaser of Class A Common Units as having the same tax benefits without regard to the actual Class A Common Units purchased. The IRS may challenge this treatment, which could result in a unitholder owing more tax and may adversely affect the value of the Class A Common Units.

To maintain the uniformity of the economic and tax characteristics of our Class A Common Units, we have adopted certain depreciation and amortization positions that are inconsistent with existing Treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding Class A Common Units. A subsequent holder of those Class A Common Units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these Class A Common Units once they are traded by the initial holder, we do not give any subsequent holder of a Class A Common Unit any such amortization deduction. This approach understates deductions available to those unitholders who own those Class A Common Units and results in a reduction in the tax basis of those Class A Common Units by the amount of the deductions that were allowable but were not taken.

The IRS may challenge the manner in which we calculate our unitholder's basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the Class A Common Units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling Class A Common Units within the period under audit as if all unitholders owned Class A Common Units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our unitholders. It also could affect the gain from a unitholder's sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties and maps depicting the locations of our liquids and natural gas systems are included in Item 1. Business, which is incorporated herein by reference.

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 2008.

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 2008 and 2007 are summarized as follows:

	First	Second	Third	Fourth
2008 Quarters				
High	$51.75	$52.98	$49.74	$40.24
Low	$44.19	$48.78	$38.00	$23.78
Cash distributions paid	$0.950	$0.950	$0.990	$0.990
2007 Quarters				
High	$56.23	$61.82	$58.47	$54.16
Low	$48.25	$52.30	$48.27	$48.71
Cash distributions paid	$0.925	$0.925	$0.925	$0.950

On February 18, 2009 the last reported sales price of our Class A common units on the NYSE was $29.11. At February 12, 2008, there were approximately 87,000 Class A common unitholders, of which there were approximately 1,485 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, our Class C units, which are held by the General Partner and institutional investors, or our i-units, all of which are held by Enbridge Management.

Private Issuance of Class A Common units to General Partner

In December 2008, we issued and sold 16.25 million Class A common units to the General Partner in a private placement for a purchase price of $30.76 per unit, or approximately $500 million. Since the transaction was private it was exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The Class A common units represent limited partner ownership interests in the Partnership and increased the General Partner's ownership in the Partnership from approximately 15 percent to approximately 27 percent. The General Partner also contributed approximately $10.2 million to us to maintain its two percent general partner interest. We used the proceeds to repay a portion of our outstanding Credit Facility borrowings that we use to finance our capital expansion projects and to repay $25 million of our Senior Notes maturing on January 15, 2009. Since the transaction involved both the Partnership and our general partner, the board of directors of Enbridge Management determined that it was advisable to form a special committee of independent directors to evaluate the transaction. The special committee engaged independent legal counsel and an independent financial advisor to advise it regarding the transaction. The special committee then approved the transaction on behalf of the Partnership.

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."

	For the year ended December 31,				
	2008	2007	2006	2005	2004
	(in millions, except per unit amounts)				
Income Statement Data:(2)(3)(4)					
Operating revenue	$10,060.0	$7,282.6	$6,509.0	$6,476.9	$4,291.7
Operating expenses	9,472.1	6,963.8	6,122.1	6,285.0	4,054.5
Operating income	587.9	318.8	386.9	191.9	237.2
Interest expense	180.6	99.8	110.5	107.7	88.4
Rate refunds	—	—	—	—	(13.6)
Other income	2.9	3.0	8.5	5.0	3.0
Income tax expense	7.0	5.1	—	—	—
Income from continuing operations	$ 403.2	$ 216.9	$ 284.9	$ 89.2	$ 138.2
Income from continuing operations per limited partner unit (basic and diluted)(1)	$ 3.63	$ 2.08	$ 3.62	$ 1.06	$ 2.06
Cash distributions paid per limited partner unit	$ 3.880	$ 3.725	$ 3.700	$ 3.700	$ 3.700
Financial Position Data (at year end):(2)(3)(4)					
Property, plant and equipment, net	$ 6,722.9	$5,554.9	$3,824.9	$3,080.0	$2,778.0
Total assets	8,300.9	6,891.6	5,223.8	4,428.4	3,770.7
Long-term debt, excluding current maturities	3,223.4	2,862.9	2,066.1	1,682.9	1,559.4
Loans from General Partner and affiliates	130.0	130.0	136.2	151.8	142.1
Partners' capital:					
Class A common units	2,104.0	1,340.7	1,141.7	1,142.4	1,021.6
Class B common units	85.0	72.9	67.6	67.2	66.7
Class C common units	886.5	874.1	509.8	—	—
i-units	553.8	515.3	466.3	421.7	399.4
General Partner	84.7	62.9	47.6	34.6	31.0
Accumulated other comprehensive income (loss)	12.9	(294.4)	(189.6)	(302.1)	(120.8)
Partners' capital	$ 3,726.9	$2,571.5	$2,043.4	$1,363.8	$1,397.9
Cash Flow Data:(2)(3)(4)					
Cash flows provided by operating activities	$ 543.3	$ 463.4	$ 321.6	$ 267.1	$ 245.4
Cash flows used in investing activities	1,428.3	1,765.0	867.0	437.1	419.1
Cash flows provided by financing activities	1,174.4	1,167.5	640.2	181.5	187.6
Additions to property, plant and equipment and acquisitions included in investing activities, net of cash acquired	1,387.1	1,980.2	897.7	531.2	429.8

Notes to Selected Financial Data:

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating income per unit: 2008, $50.7 million; 2007, $37.7 million; 2006, $30.9 million; 2005, $23.5 million; and 2004, $22.5 million.

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

- April 2006, acquisition of a natural gas pipeline in east Texas;
- 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; and
- March 2004 acquisition of Mid-Continent system.

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

- The December 2008 issuance of $500 million of 9.875% senior notes;
- The April 2008 issuance of $400 million of 6.5% senior notes and $400 million of 7.5% senior notes;
- The December 2007 issuance of $130 million note payable to Enbridge Hungary Ltd. and the simultaneous repayment of a $145 million note payable to Enbridge Hungary Ltd., including $8.8 million of accrued interest;
- The September 2007 issuance of $400 million of junior subordinated notes;
- The August 2007 issuance of $200 million of zero coupon senior unsecured notes and $3.6 million of accreted interest;
- The April 2007 amendment of our credit facility, which increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion, allows us to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion, eliminates the letter of credit sublimit and extends the maturity to 2012;
- The December 2006 issuance of $300 million of senior unsecured notes;
- The September 2005 amendment of our credit facility to extend the letter of credit sublimit from $175 million to $300 million and increase the commitments available from $600 million to $800 million maturing in 2010, and the subsequent extension of the commitments available to $1 billion in March 2006.
- 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; and
- The January 2004 issuance of $200 million of senior unsecured notes.

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

- The December 2008 private issuance of 16.25 million Class A common units to our general partner;
- The March 2008 issuance of 4.6 million Class A common units;
- The May 2007 issuance of 5.3 million Class A common units;
- The April 2007 issuance of approximately 5.9 million Class C units to institutional investors;
- The August 2006 issuance of approximately 10.8 million Class C units in equal amounts to our general partner and an institutional investor;
- The December 2005 issuance of 0.13 million Class A common units; the November 2005 issuance of 3.0 million Class A common units; and the February 2005 issuance of 2.5 million Class A common units;
- The September 2004 issuance of 3.68 million Class A common units; and the January 2004 issuance of 0.45 million Class A common units;
- The quarterly in-kind distributions of 1.2 million, 0.9 million, 1.0 million, 0.8 million, and 0.8 million i-units during 2008, 2007, 2006, 2005 and 2004, respectively, in lieu of cash distributions; and
- The quarterly in-kind distributions of 1.6 million, 1.1 million and 0.2 million Class C units during 2008, 2007 and 2006, 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.

IMPACT OF CURRENT ECONOMIC CRISIS

Multiple events during 2008, involving the financial sector of the global economy, have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators to provide liquidity to the financial sector, capital markets continue to remain constrained. We expect our access to the capital markets to be restricted over the next twelve months and possibly longer should capital markets remain dysfunctional. As a result, our ability to raise debt and equity at prices that are similar to offerings in recent years will continue to be limited. See "Liquidity and Capital Resources – Impact of Current Economic Crisis" for additional discussion about the effect of the current economic crisis on us.

The current economic crisis has created a challenging operating environment for us. We are acting decisively to address this crisis through enhanced management of our operating costs and discretionary capital spending. We intend to move forward with our commercially supported internal growth projects, predominately within our Liquids business.

Our ability to access the capital markets to fund new projects in the near term is likely to be limited. We are also considering non-traditional sources of financing for our growth projects such as private equity, asset partnership arrangements and non-core asset sales. Over the next 18 months, we will focus on preserving sufficient liquidity to fund our growth programs and maintaining our present distribution rate per unit.

At December 31, 2008, we have in excess of $1.8 billion of liquidity to meet our ongoing operational and investment and finance needs, which we have determined as follows:

	2008
	(in millions)
Availability under Credit Facility	$ 998.9
Available under Enbridge (U.S.) Credit Agreement	500.0
Cash and cash equivalents	339.9
Total	$1,838.8

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 natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling 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.

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

	2008	2007	2006
		(in millions)	
Operating Income			
Liquids	$342.2	$207.1	$199.8
Natural Gas	245.2	91.2	133.9
Marketing	7.6	24.0	56.1
Corporate, operating and administrative	(7.1)	(3.5)	(2.9)
Total Operating Income	587.9	318.8	386.9
Interest expense	180.6	99.8	110.5
Other income	2.9	3.0	8.5
Income tax expense	7.0	5.1	—
Income from continuing operations	403.2	216.9	284.9
Income from discontinued operations	—	32.6	—
Net Income	$403.2	$249.5	$284.9

Contractual 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. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be very significant as evidenced by commodity prices during 2008. We employ derivative financial instruments to hedge a portion of our commodity position and 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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("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.

Summary Analysis of Operating Results

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. These systems largely consist of FERC-regulated interstate crude oil and liquid petroleum pipelines. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. These systems generate revenues primarily from charging shippers a rate per barrel to transport and store crude oil and liquid petroleum.

Operating income from our Liquids segment increased $135.1 million to $342.2 million for the year ended December 31, 2008 from the $207.1 million contributed for the year ended December 31, 2007. The increase in operating income of our Liquids segment is primarily due to the following:

- Tariff increases that went into effect in April 2008 associated with our Southern Access Expansion and in January 2008 for the Phase V expansion of our North Dakota system;
- Additional revenue resulting from higher average crude oil prices associated with the allowance oil we receive in connection with our transportation services; and
- Higher delivery volumes on our Lakehead system.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, including three 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 associated with the services we provide to gather and process natural gas and to transport natural gas on our pipelines. Generally, our revenues are in the form of fee for service arrangements and/or sales of natural gas and natural gas liquids.

Operating income from our Natural Gas segment increased by $154.0 million to $245.2 million for the year ended December 31, 2008 from $91.2 million for the year ended December 31, 2007. The following factors affected the operating income of our Natural Gas segment:

- $85.0 million of unrealized, non-cash mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133 for the year ended December 31, 2008, as compared with net losses of $59.0 million for the same period of 2007;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;
- Lower processing margins resulting from higher average prices for natural gas used for processing, coupled with a continued shift in our contract mix from keep-whole to percentage of liquids, or POL, type contracts;
- Reduced revenues of approximately $14 million associated with the impact of hurricanes Gustav and Ike, when third-party facilities downstream of our operations were damaged or without power. Physical damage to our facilities was minimal, although we did incur capital and operating costs approximating $1 million for repairs to several of our natural gas systems during the third and fourth quarters of 2008. Our three major natural gas systems have been returned to pre-hurricane levels;
- Declines in the prices of natural gas and NGLs from July 2008 through December 31, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to net realizable value; and
- Variable operating and administrative cost increases associated with our system growth.

Marketing

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.

Operating income from our Marketing segment decreased $16.4 million to $7.6 million for the year ended December 31, 2008 from $24.0 million for the comparable period in 2007. The change in operating income of our Marketing segment is primarily a result of the following:

- Unrealized, non-cash mark-to-market net losses for 2008 of $16.2 million compared with non-cash mark-to-market net losses of $3.8 million for 2007, resulting from the change in market value of our derivative financial instruments that do not qualify for hedge accounting; and
- Non-cash charges of $7.5 million in 2008, resulting from a reduction of the cost basis of our natural gas inventory to market value, which is $3.2 million more than the $4.3 million we recorded in 2007.

Derivative Transactions and Hedging Activities

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133, and the guidance set forth in Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS No. 157"). For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Declining commodity prices in the second half of 2008 produced $68.8 million of unrealized, non-cash mark-to-market net gains, primarily from derivative financial instruments we use to hedge our optional NGL production. During the year ended December 31, 2007, rising NGL prices coupled with relatively stable natural gas prices produced $62.8 million of unrealized non-cash mark-to-market net losses from derivative financial instruments we use to hedge our option NGL production. The increases in fair value of our portfolio of commodity-based derivative instruments that do not qualify for hedge accounting result when the underlying prices for natural gas, NGLs and crude oil decline below the prices set forth in the derivative contracts. Likewise, decreases in the fair value of our portfolio of derivative financial instruments result when the underlying prices for natural gas, natural gas, NGLs and crude oil increase above the prices set forth in the derivative contracts. Mark-to-market gains or losses create volatility in our operating results although the derivative instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative instruments against the underlying physical transactions. We intend to continue using derivative instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from reducing the volatility in our cash flows. Our continued use of derivative instruments is likely to result in additional unrealized, non-cash gains and losses in the future.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, 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 consolidated statements of cash flows:

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ (0.1)	$ —	$ (1.9)
Non-qualified hedges	85.1	(59.0)	1.8
Marketing			
Non-qualified hedges	(16.2)	(3.8)	64.5
Commodity derivative fair value gains (losses)	68.8	(62.8)	64.4
Corporate			
Non-qualified interest rate hedges	—	(1.4)	—
Derivative fair value gains (losses)	$ 68.8	$(64.2)	$64.4

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:

	For the year ended December 31,		
	2008	2007	2006
	(dollars in millions)		
Operating Results			
Operating revenues	$773.1	$548.1	$512.8
Operating and administrative	189.4	156.1	141.3
Power	140.7	117.0	107.6
Depreciation and amortization	100.8	67.9	64.1
Operating expenses	430.9	341.0	313.0
Operating Income	$342.2	$207.1	$199.8
Operating Statistics			
Lakehead system:			
United States(1)	1,267	1,202	1,204
Province of Ontario(1)	353	341	313
Total Lakehead system deliveries(1)	1,620	1,543	1,517
Barrel miles (billions)	432	408	400
Average haul (miles)	729	725	722
Mid-Continent system deliveries(1)	231	236	244
North Dakota system:			
Trunkline	105	91	85
Gathering	6	7	7
Total North Dakota system deliveries(1)	111	98	92
Total Liquids Segment Delivery Volumes(1)	1,962	1,877	1,853

(1) Average barrels per day in thousands.

Year ended December 31, 2008 compared with year ended December 31, 2007

Our Liquids segment accounted for $342.2 million of operating income for the year ended December 31, 2008, representing an increase of $135.1 over the same period in 2007. The favorable results are attributable to transportation rate increases that went into effect during 2008, together with higher volumes transported on our Liquids systems, partially offset by higher power, operating and administrative costs, and depreciation.

Operating revenue for the year ended December 31, 2008 increased by $225.0 million to $773.1 million from $548.1 million for the same period in 2007. The increase in operating revenue is due to the following:

- Increased average rates for transportation on all of our major systems as noted below;
- Higher delivery volumes on our Lakehead and North Dakota systems;
- Additional revenue resulting from higher crude oil prices associated with the allowance oil we receive in connection with our transportation services; and

- Additional contract storage fees revenue generated by our Mid-Continent storage terminal system.

Increases in average transportation rates on all three Liquids systems together with longer hauls contributed approximately $170.5 million of additional operating revenue. We filed new tariff rates in 2008 on our Lakehead system, effective April 1, 2008, to reflect the recent completion of four projects: (1) the Southern Access mainline expansion, (2) two Superior terminal tank projects, (3) two Griffith terminal tank projects and (4) the Clearbrook Manifold project. We also implemented new tariff rates on our North Dakota system, effective January 1, 2008, to reflect the completion of our North Dakota Phase V expansion. Additionally, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment that went into effect July 1, 2008.

Average delivery volumes on our Lakehead system increased approximately 5.0 percent, to 1.620 million Bpd for the year ended December 31, 2008 from 1.543 million Bpd during the same period in 2007. This increase contributed an additional $22.8 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the oil sands in Alberta, Canada ("Alberta Oil Sands").

Our transportation tariff allows our pipelines to deduct an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the year ended December 31, 2008 were substantially higher than the average prices for the same period of 2007. For example, the average price of West Texas Intermediate crude oil has increased approximately 38 percent for the year ended December 31, 2008 as compared with the same period in 2007. As a result of the increase in crude oil prices, we experienced an approximate $18.6 million increase in allowance oil revenues.

Also contributing to the increase in revenues for the year ended December 31, 2008, was an approximately $8.7 million increase in contract storage and spot storage fees generated by our Mid-Continent storage terminal system from the additional storage tanks we placed in service during mid and late 2007. Across our Mid-Continent system, we added a net of seven storage tanks during 2007 contributing an additional 3.8 million barrels of capacity bringing the total storage capacity to approximately 16.7 million barrels and 106 tanks. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Operating and administrative expenses for the Liquids segment increased $33.3 million for the year ended December 31, 2008, compared with the same period in 2007. The increase in these costs is primarily attributable to the following:

- Additional workforce related costs for the operational, administrative, regulatory, and compliance support services necessary for our growing systems;
- Increased costs related to repair and maintenance activities;
- Unfavorable oil measurement adjustments as described below;
- Further costs incurred in connection with the crude oil release and fire on Line 3 of our Lakehead system; and
- Modest increases in property taxes due to favorable settlements of property tax assessments that we realized during the year ended December 31, 2007 which were not present for the same period in 2008.

Our general partner charges us the costs associated with employees and related benefits for personnel who are assigned to us or otherwise provide us with managerial and administrative services. We have experienced an increase in workforce related costs as a result of the growth and expansion of our Liquids system operations.

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum pipelines. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;

- Degradation, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Power costs increased $23.7 million in the year ended December 31, 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs associated with volatile pricing of these commodities.

The increase in depreciation expense of $32.9 million is attributable to the additional assets we have placed in service during 2007 and for the year ended December 31, 2008, including the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008 along with the assets placed into service on our North Dakota and Mid-Continent systems.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Liquids segment accounted for $207.1 million of operating income in 2007, representing an increase of $7.3 million over 2006. The favorable results of our Liquids business reflect modest growth in our transportation volumes while actively managing the costs of our services. The majority of this increase related to improved results on our Lakehead system.

Operating revenue for the year ended December 31, 2007 increased by $35.3 million to $548.1 million from $512.8 million for the same period in 2006. The increase in revenue is primarily attributable to the higher delivery volumes on our Lakehead and North Dakota systems combined with the increase in average transportation rates associated with the annual index rate increase that went into effect July 1, 2007, for all three of our liquids systems. We increased the transportation rates on our Lakehead system by an average of 4.5 percent and on our Ozark and North Dakota systems by an average of 4.3 percent. Additionally, new tariffs went into effect April 1, 2007, on our Lakehead system to reflect the annual calculation of the SEP II and other surcharges, as well as an adjustment for the Terrace surcharge due to lower than expected volumes moving on the Lakehead system in 2006. The transportation rate increases of our Liquids systems contributed approximately $15 million to the increase in our revenues for the year ended December 31, 2007.

Also contributing to the increase in revenues for the year ended December 31, 2007, was a $5 million increase in contract storage fees generated by our Mid-Continent storage terminal system from the additional storage tanks we placed in service during 2007 and in late 2006. Across our Mid-Continent system, we added a net of seven storage tanks during 2007 contributing an additional 3.8 million barrels of capacity, bringing the total storage capacity to approximately 16.7 million barrels and 106 tanks. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Average delivery volumes on our Liquids systems increased to 1.877 million Bpd for the year ended December 31, 2007, from the 1.853 million Bpd during the same period in 2006, accounting for approximately $9 million of the increase in the operating revenues of our Liquids segment. The increase in average deliveries on our Liquids systems are primarily derived from modest production increases of western Canadian crude oil delivered on our Lakehead system. The increase in deliveries is attributable to the following:

- Crude oil supplies increased from upstream production facilities associated with the ongoing development of the Alberta Oil Sands by producers;
- Our Mid-Continent system continues to operate near capacity; and
- Volume growth on our North Dakota system associated with completion of our hydrostatic testing program and phasing in portions of a system expansion that was completed in the fourth quarter of 2007.

Operating and administrative expenses for the year ended December 31, 2007 were $156.1 million or $14.8 million greater than the $141.3 million for the same period in 2006. The increase in these costs is primarily attributable to the following:

- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our growing systems;
- Further costs we incurred in connection with our pipeline integrity program; and
- Property damage we sustained in connection with a crude oil release and fire on Line 3 of our Lakehead system.

Workforce related costs increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our growing systems as discussed above in the year end analysis for December 31, 2008. The increase in operating and administrative costs is partially offset by a reduction for field inventory expenses we realized in 2006 that we did not incur in 2007.

Our pipeline systems consist of individual pipelines of varying ages from approximately 55 years to newly constructed. With appropriate inspection and maintenance, the physical life of a pipeline is indefinitely long. However, as our pipelines age we anticipate that the level of expenditures required for inspection, renewal and maintenance will increase. In addition, we have established temporary pressure restrictions on some sections of some of our pipelines pending completion of specific inspection and renewal programs, and may from time to time establish further temporary pressure restrictions. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. The loss of throughput to date, resulting from pressure restrictions, has not materially affected our operating results.

Power costs increased $9.4 million in 2007, compared with 2006, predominantly due to the higher utility rates we are charged by our power suppliers. The increase in delivery volumes is also a factor contributing to the additional power costs. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas costs.

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. Combined conventional and oil sands established reserves of approximately 178 billion barrels compare with Saudi Arabia's proved reserves of approximately 264 billion barrels. The National Energy Board of Canada, or NEB, estimates that total WCSB production averaged approximately 2.4 million Bpd in 2008 and 2007. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. CAPP’s December 2008 estimates of future production from the Alberta Oil Sands is expected to grow steadily during the next 10 years, with an additional 1.8 million Bpd of incremental supply available by 2018, based on a subset of currently approved applications and announced expansions. We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets in the United States.

Crude oil price volatility in 2008 has caused some oil sands producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals of oil sands projects are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the Western Canadian Sedimentary Basin declines, immediate need for new pipeline infrastructures will likely decline. In addition to our expansions, a new competitor is expected to complete construction of a pipeline system to Wood River and Patoka, Illinois, and to Cushing, Oklahoma, with an initial capacity of 435,000 Bpd and an ultimate capacity of 590,000 Bpd. This competing pipeline, together with our Southern Access and Alberta Clipper expansions may provide sufficient capacity for the near-term. If this is the case, we expect expansion activities in and around our Lakehead system to continue but they may be more modest than experienced over the last several years.

Status of Partnership Projects

Southern Access

We continue to progress on schedule on the second and final stage of the Southern Access expansion project which will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois. We commenced construction of this stage of the project on June 1, 2008 and expect to complete the project by the end of the first quarter of 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 which can be further expanded to 1.2 million Bpd with expenditures for additional pumping equipment. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. We anticipate that earnings before interest, taxes, depreciation, and amortization ("EBITDA") associated with this project will be approximate $230 million annually in the first full year that both stages of the Southern Access project are fully operational.

Alberta Clipper

The Alberta Clipper project involves construction of a new 36-inch diameter, 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior, generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, Wisconsin, a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.2 billion. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing with the project, which is expected to be in service in mid-2010. We expect to begin construction on the U.S. leg of the project in mid-2009. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. We anticipate that the first full year EBITDA resulting from the completion of this project will approximate $170 million.

North Dakota

The United States Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated natural gas resources of the Upper Devonian—Lower Mississippi Bakken formation in the United States portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil. Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. As a result, we have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. The proposed tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the FERC in October 2008. The Phase VI expansion is expected to be in service in early 2010.

Trailbreaker (formerly Eastern PADD II Access)

We and Enbridge initiated plans to provide access for western Canadian crude oil to refineries along the United States Eastern Seaboard and the United States Gulf Coast via the marine terminal at Portland, Maine. The Trailbreaker project contemplates the expansion and reversal of existing facilities to create a pipeline route to Portland. An open season process held by third-party owned Portland-Montreal Pipe Line did not receive sufficient commercial support for the reversal of one of its pipelines to transport crude oil from Montreal, Quebec to Portland. As a result, CAPP has exercised its right to withdraw support from the project at this time. Enbridge continues to engage in discussions with customers to determine timing and conditions for proceeding with this project.

Enbridge and Other Projects

Spearhead Pipeline

In a further effort to provide shippers access to new markets, Enbridge acquired a pipeline that previously shipped crude oil from Cushing, Oklahoma to Chicago. Enbridge reversed the pipeline, renamed it Spearhead, and began delivering Canadian crude oil to the major oil hub at Cushing in March 2006. Since then, the pipeline has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 193,300 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. Construction has commenced on the 68,300 Bpd expansion, which is expected to be completed on schedule in early 2009. The Spearhead pipeline is complementary to our Lakehead system as western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and the CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Project timing is being re-evaluated as a result of delays in the regulatory process and the May 2008 denial by the FERC of Enbridge's October 2007 filing seeking a declaratory order of the tariff rate structure for the pipeline. Enbridge remains committed to meeting the shippers' need for transportation of crude oil from the Chicago area to the Patoka, Illinois hub and is working with customers to reposition the project in a manner that is commercially appropriate for the market and includes a tolling structure acceptable to the FERC.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta Oil Sands. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line. The project involves the exchange of a 156-mile section of pipeline we own, referred to as Line 13, for a similar section of a new pipeline to be constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us.

In February 2008, the NEB issued its approval and, in May 2008, the Canadian Government also issued its Governor In Council ("GIC") approval for the Canadian portion of the Southern Lights project, which allowed construction to commence. Enbridge has filed the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. These processes are expected to be resolved in the first half of 2009, enabling construction for the remaining U.S. portion of the project to commence in 2009. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of Line 13 discussed above, which the FERC approved in late December 2007. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Construction and right-of-way acquisition related to this project continues in tandem with the Southern Access project. This project is expected to be placed in service in 2010.

United States Gulf Coast Joint Initiative

In August 2008, Enbridge and BP Pipelines (North America) Inc. ("BP") announced they are currently developing an initiative to deliver incremental volumes of Canadian crude oil to the U.S. Gulf Coast. The initiative, as envisioned, involves the reversal of the BP #1 pipeline system between Flanagan and Cushing, as well as the construction of a new pipeline between Cushing and Houston, Texas. The scope of the project provides for a pipeline system with over 150,000 Bpd of new capacity between Flanagan and Cushing and approximately 250,000 Bpd of capacity between Cushing and Houston. Enbridge is currently working with BP to develop commercial terms to present to a targeted list of potential shippers to solicit binding support prior to launching an open season in 2009. The target in-service date for this pipeline system is late 2012.

Other Matters

In September 2007, the Alberta Royalty Review Panel issued its recommendations to the government of the Province of Alberta calling for the adoption of measures to increase the Alberta government's share of revenues from oil sands development. A majority of the recommendations of the report were subsequently adopted by the Alberta government and became effective January 1, 2009. These measures may impact how oil sands developers evaluate future projects and this may reduce the level of future volumes we expect to flow through the Enbridge/Lakehead mainline system.

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 11,700 miles of natural gas gathering and transmission pipelines including three FERC-regulated transmission pipeline systems;
- Nine natural gas treating plants and 24 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:

	For the year ended December 31,		
	2008	**2007**	**2006**
		(dollars in millions)	
Operating revenues	$ 4,677.1	$ 3,444.0	$ 3,020.7
Cost of natural gas	3,982.4	2,990.0	2,601.1
Operating and administrative	328.5	266.7	215.4
Depreciation and amortization	121.0	96.1	70.3
Operating expenses	4,431.9	3,352.8	2,886.8
Operating Income	$ 245.2	$ 91.2	$ 133.9
Operating Statistics (MMBtu/d)			
East Texas	1,479,000	1,180,000	1,019,000
Anadarko	647,000	591,000	582,000
North Texas	395,000	348,000	294,000
UTOS	128,000	192,000	181,000
MidLa	99,000	115,000	109,000
AlaTenn	42,000	44,000	41,000
Bamagas	87,000	119,000	88,000
Other major intrastates	213,000	236,000	223,000
Total[1]	3,090,000	2,825,000	2,537,000

(1) In November 2007, we sold the KPC system which contributed average daily volumes of approximately 23,000 and 29,000 for the years ended December 31, 2007 and 2006.

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectability 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 our Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on both our FERC-regulated interstate natural gas transmission pipeline systems and some of our intrastate pipeline systems. Customers paying these fees typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. Additional revenues from our intrastate pipelines are derived from the bundled sales of natural gas and transmission services.

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 hedge a significant amount of our exposure to commodity price risk to support the stability of our cash flows. 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 the derivative activities we use to mitigate our exposure to commodity price risk.

We categorize our other types of arrangements as follows:

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. 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 at market prices, the resulting residue gas. 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 an energy content equivalent to the original raw natural gas we received as measured in British thermal units, or Btu.
- 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 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.

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. We enter into derivative financial instruments to hedge approximately 60 to 80 percent of our near-term exposure to commodity prices associated with the in-kind compensation we receive for our services. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the processed natural gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate during that time. Many of the derivative financial instruments we use do not qualify for hedge accounting. As a result we record the changes in fair value of the derivative instruments that do not qualify for hedge accounting in our operating results. This accounting treatment produces unrealized non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

Year ended December 31, 2008 compared with year ended December 31, 2007

Our Natural Gas segment contributed $245.2 million of operating income for the year ended December 31, 2008, an increase of $154.0 million from the $91.2 million contributed in the corresponding period of 2007. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the year ended December 31, 2008 as compared with the same period of 2007:

- $85.0 million of unrealized, non-cash mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $59.0 million for the same period of 2007;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;
- Reduced revenues of approximately $14 million associated with the impact of hurricanes Gustav and Ike in the third and fourth quarters of 2008, when third-party facilities downstream of our operations were damaged or without power. Physical damage to our facilities was minimal with certain of our natural gas assets incurring capital and operating costs of approximately $1 million for repairs. Our three major natural gas systems have been returned to pre-hurricane levels;
- Increased use of fee-based arrangements to compensate for our services at lower margins relative to contract structures that contain commodity price risk;
- Declines in the prices of natural gas and NGLs from July 2008 to December 31, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to net realizable value; and
- Increased workforce, repair and maintenance, materials and supplies, property taxes and depreciation associated with our system growth.

The operating income of our Natural Gas segment for the year ended December 31, 2008 was positively affected by unrealized non-cash, mark-to-market net gains of $85.0 million, representing an increase of $144.0 million from the $59.0 million of losses we recorded for the same period of 2007. During the second half of 2008, significant declines in the forward and daily market prices of natural gas, NGLs and condensate produced non-cash, mark-to-market net gains in our portfolio of derivative instruments. The declining price environment that was prevalent during the second half of 2008 was not present during most of the year ended December 31, 2007. We expect the net mark-to-market gains to be offset when the related physical transactions are settled.

We are exposed to fluctuations in commodity prices in the near term on approximately 20 to 40 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our margins increase when the prices of these commodities are rising and decrease when the prices are declining.

Despite the substantial fluctuations in commodity prices during 2008, an overall favorable pricing environment contributed to higher average prices for the sale of natural gas and NGLs we receive as in-kind payment for our services. The improved margins were also enhanced by an approximate 10% increase in average daily volumes on our natural gas systems. The increase in average daily volume of our Natural Gas business is directly attributable to the significant investments we have made to expand the capacity and service capability of our systems. We completed the following projects during the years ended December 31, 2008 and 2007, which have contributed to the increase in average daily volumes and operating results of our major natural gas systems:

- In May 2008 our expansion of the Aker treating plant on our East Texas system was completed and placed into service adding 125 million cubic feet per day, or MMcf/d, of treating capacity.
- The $655 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, is substantially complete and includes:
  - ➢ The Goodrich compressor station was constructed and placed into service in December 2008;
  - ➢ A 36-inch diameter pipeline segment that extends from Kountze, Texas to Orange County, Texas was placed into service in July 2008;
  - ➢ A 20-inch segment from Orange County, Texas to a downstream interconnect near Beaumont, Texas enabling deliveries into the interconnect was placed into service in December 2008;
  - ➢ Construction of the Orange County, Texas compressor station is nearly complete and is expected to be placed into service in February 2009;
  - ➢ A 36-inch diameter pipeline that extends from Goodrich to Kountze was completed in October 2007, which enables deliveries into a major interstate pipeline;
  - ➢ A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel, Texas to Crockett was completed and placed into service in late July 2007;
  - ➢ A 20-inch diameter pipeline in close proximity to our Marquez treating facility was completed and placed into service in June 2007;
  - ➢ A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett, Texas and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007; and
  - ➢ The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed into service in March 2007.

  We expect to finish the final compression station during the first quarter of 2009. The total added capacity related to this project when completed will approximate 700 MMcf/d.
- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- Construction of the Weatherford gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d. At the end of 2007, additional processing capacity was added to the Weatherford processing facility to increase its capacity from 35 MMcf/day to 75/MMcf/day.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction of the Hidetown processing facility on our Anadarko system with approximate capacity of 120 MMcf/d was completed and placed into service at the end of April 2007.
- During the second quarter of 2007, we refurbished our Zybach processing plant to address operational inefficiencies experienced by the plant. As a result of the service and repairs, processing volumes were restored to expected levels.

With the expansions we completed in 2008 and 2007, we are now able to provide additional gathering, processing, treating and transportation services for our customers which has contributed to our volume growth for the year ended December 31, 2008. Volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale and Granite Wash areas. We expect the volumes on our major natural gas systems to continue increasing throughout the upcoming year as a result of our investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve. Another factor that could lead to more demand on our services is the recent discovery of the Haynesville Shale in western Louisiana and eastern Texas. The Haynesville Shale has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system increasing the demand for our services.

A factor that may moderate increased demand in fiscal year 2009 is the deteriorated state of the global economy. Weak demand together with low commodity prices may lead to the inability of many companies to raise the necessary capital to engage in new projects. The inability to obtain the necessary funding for new capital projects could decrease the amount of new natural gas production in the areas we serve.

The processing margins we derive from processing natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems declined 25 percent for the year ended December 31, 2008 in relation to the same period of 2007. Operating income derived from keep-whole processing arrangements for the year ended December 31, 2008 was $81.9 million, representing a decrease of $26.8 million from the $108.8 million we produced for the same period in 2007. During the last half of 2008, NGL and crude oil prices began to decline faster than natural gas prices, which have the effect of reducing revenue we derive from our processing assets. In addition we continue to experience a trend of replacing or renegotiating some of our existing keep-whole contracts with percentage of liquids, or POL, type contracts and other similar arrangements. This trend should reduce our exposure to the commodity price spread between natural gas and NGLs for the portion of the operating income we derive from processing natural gas under keep-whole arrangements.

During the months from September to December 2008, we experienced operational disruptions to our onshore and offshore natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities in Texas and Louisiana sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues for the months of September through December due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants, transport natural gas to markets, and to access natural gas liquids we own at third party facilities held under force majeure. Our current estimate of lost revenue associated with the hurricanes approximates $14 million. In addition we incurred capital and operating costs of approximately $1 million for repairs to our damaged facilities in the year ended December 31, 2008. We do not anticipate recovery of any of these losses through insurance. The majority of our facilities returned to normal operation by the end of September 2008.

As a result of the significant price erosion in daily natural gas prices in the second half of 2008, we recorded $6.4 million of revaluation losses with respect to our in-kind natural gas imbalances. NGL prices also experienced similar declines in prices which required us to recognize $4.1 million of charges to reduce the cost basis of our NGLs.

Operating and administrative costs of our Natural Gas segment were $61.8 million greater for the year ended December 31, 2008 compared to the same period in 2007, primarily as a result of increased workforce-related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly due to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our natural gas systems. We expect workforce related costs in addition to materials, supplies and other costs to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher for the year ended December 31, 2008 as compared to the same period in 2007, as a result of the capital projects completed and placed into service throughout 2008 and the last quarter of 2007.

In September 2008, we acquired the transportation assets of Petron, a trucking company located in Alexandria, Louisiana, for $7.7 million in cash. The acquisition was necessitated by the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as the need to better serve our U.S. Gulf Coast customers. The operations of the newly acquired truck fleet increased our operating and administrative expenses for the fourth quarter of 2008.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Natural Gas segment produced $91.2 million of operating income for the year ended December 31, 2007, a decrease of $42.7 million from the $133.9 million of operating income generated during the prior year. Operating income in 2007 included unrealized, non-cash mark-to-market net losses from our derivative activities totaling $59.0 million which are $58.9 million more than the $0.1 million of net losses we recorded in the same period of 2006. Also contributing to operating income were volume increases, improved pricing for our services and greater processing margins, which represent revenues less the cost of natural gas purchased for processing. Partially offsetting these increases in operating income were higher operating costs and depreciation.

The operating income of our Natural Gas segment for the year ended December 31, 2007 was negatively affected by unrealized non-cash, mark-to-market net losses of $59.0 million from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. These losses were predominantly the result of hedges placed on the optional processing we perform on our three major systems which do not qualify for hedge accounting. In 2006, our operating income was reduced by unrealized non-cash, mark-to-market net losses of $0.1 million, including $1.9 million of losses that resulted from ineffectiveness of our cash flow hedges and $1.8 million of gains derived from our derivative financial instruments that did not qualify for hedge accounting treatment under SFAS No. 133. Refer also 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.

Average daily volumes on our major natural gas systems increased 11 percent, or approximately 288,000 MMBtu/d, for the year ended December 31, 2007, compared with the corresponding period of 2006. The increased volumes for 2007 continue to reflect our ongoing investments to further expand the capacity of our systems and services. We completed the following projects during 2006 which have contributed to the increases in average daily volumes and operating results of our major natural gas systems:

- Construction of our Henderson natural gas processing facility on our East Texas system was completed and operating at the end of the third quarter of 2006 with a capacity of 120 MMcf/d; and
- A link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005.

During 2007, we have added approximately 195 MMcf/d of additional processing capacity to our Natural Gas systems, which has served to increase our processing margin. During 2007, NGL prices continued to trend higher relative to natural gas prices, providing a favorable environment for the production of NGLs from our processing assets, similar to the pricing environment experienced during 2006. A variable element of our Natural Gas segment's operating income is derived from the processing of natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems. Operating income derived from our keep-whole processing increased to approximately $108.8 million for the year ended December 31, 2007 from $79.2 million for the same period in 2006 primarily due to the current favorable pricing environment and increased volumes processed associated with these types of arrangements and increased processing plant capacity. Partially offsetting our favorable processing results were operational issues associated with our Zybach processing plant that occurred during the first quarter of 2007 which reduced processing margins by approximately $10.5 million. We completed the necessary repairs and modifications during April 2007 and the plant operated as expected throughout the remainder of 2007.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather temperatures and variances in measurement that are inherent in metering technologies. During the first quarter 2007, we identified operating conditions on our gathering systems which contributed to an increase in measurement losses. We have since installed separator equipment to identify and eliminate free-water in the natural gas streams, one of the underlying causes for the increase in measurement losses during 2007. For the year ended December 31, 2007, we estimate that measurement losses resulted in approximately $21.3 million of additional cost to our natural gas systems relative to the same period of 2006.

A portion of our Natural Gas segment is exposed to risks from fluctuations in commodity prices associated with the percentage of proceeds, percentage of liquids, and percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to 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 pay for natural gas and 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. Another significant portion of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services which are not directly dependent on commodity prices.

Operating and administrative costs associated with our Natural Gas segment were $51.3 million, or 24 percent, greater for 2007 than 2006, primarily as a result of increased workforce related cost associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our workforce related costs increased for the year ended December 31, 2007 over the same period in 2006 due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. In addition, our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of continuous pipeline expansions across the areas we serve.

Our materials and supplies coupled with repair and maintenance costs increased for the year ended December 31, 2007 over the same period in 2006, predominantly due to the increase in volumes and expansion of our natural gas systems. Materials, supplies and other costs include chemicals used in our processing activities, materials purchased for repair and maintenance purposes, utility costs to run our plants, pumps and other similar costs that are mostly variable with volumes. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. An example of these increasing costs is methanol, a chemical used on our systems which cost $2.06 per gallon in 2006. At the end of 2007, this chemical had risen in cost to $2.49 per gallon. Welders, inspectors and other skilled laborers and technicians hourly labor costs have increased in cost by amounts well in excess of the rate of overall inflation as measured by the CPI or PPI inflation index. We expect our operating and administrative costs will continue to increase in future periods as greater volumes of natural gas flow through our systems and we continue to expand our natural gas operations.

Our depreciation and amortization expense for the year ended December 31, 2007 increased by approximately $25.8 million over the same period in 2006, primarily as a result of capital projects completed and placed in-service during late 2006 and throughout 2007. We expect our depreciation expense to continue to increase as we complete capital projects related to our continued expansion of our natural gas operations.

Future Prospects for Natural Gas

Volatility in the capital markets will necessitate a less aggressive capital program in our natural gas business in the near term. During this period of volatility we will continue to focus our efforts primarily on development of our existing pipeline systems. We have evaluated all of our planned future Natural Gas projects and have written off approximately $4 million of projects that were uneconomic at December 31, 2008. We have also delayed other projects until such time that capital becomes available at more economical costs for those projects with sufficient commercial support. We will opportunistically evaluate strategic prospects to further expand the service capabilities of our existing system.

We may also pursue opportunities to divest any non-strategic natural gas assets as conditions warrant. In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), LLC, a wholly-owned subsidiary of Enbridge. 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 contracts. The UTOS system was not considered strategic to the ongoing operations of the Partnership and was an insignificant contributor to the financial results of our Natural Gas segment.

Results of our Natural Gas business depend upon the drilling activities of natural gas producers in the areas we serve. We expect the rapid decline in natural gas and NGL prices during the second half of 2008 to reduce exploration and production activity by natural gas producers in the near term, which may diminish the growth rate of our Natural Gas business. Specifically, we expect the volumes on our Anadarko system to decline from historic levels due to weak commodity prices in the Midcontinent region of the United States among other economic factors. However, our East Texas and North Texas systems are located in two areas where we believe producers are likely to remain active due to the higher probability of success associated with resource developments in these areas. Another factor that could lead to additional demand for the services of our East Texas system is the recent natural gas discovery in the Haynesville Shale play located in western Louisiana and eastern Texas. The Haynesville Shale has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system increasing the demand for our services. We believe these factors should temper the impact of lower natural gas production that generally results from a reduction in drilling activity.

Shelby County Loop and Compression

We commenced construction during the third quarter of 2008 to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. We have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. We expect to complete this project during 2009 at an approximate cost of $60 million. Commercial terms for this project predominately involve firm volume commitments from customers.

Other Matters

A number of new interstate natural gas transportation pipelines are being constructed that may alter the landscape for interstate transportation of natural gas. These newly constructed pipelines could affect the operating results of certain of our existing market-based interstate and intrastate natural gas pipelines, primarily the AlaTenn, Midla, and MLGT systems. Conversely, our supply-based gathering systems may benefit from enhanced capacity out of our gathering areas.

We completed negotiations with a major customer of our Midla mainline transmission system for the renewal of a contract that expired in August 2008 for another five year term. Unlike our gathering systems, our interstate pipelines have a concentration of customers. As such they are more susceptible to contract loss or competition and potentially the inability to recover the carrying value of their noncurrent assets, which approximate $30 million for the Midla system and $45 million of the AlaTenn system at December 31, 2008.

In November 2007, we sold our Kansas pipeline system, or KPC, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. KPC represented a business within our Natural Gas segment that we did not consider strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the years ended December 31, 2007, 2006 and 2005. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

Marketing

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

	For the year ended December 31,		
	2008	2007	2006
	(dollars in millions)		
Operating revenues	$4,609.8	$3,290.5	$2,975.5
Cost of natural gas	4,590.5	3,256.9	2,913.5
Operating and administrative	10.1	8.0	5.4
Depreciation and amortization	1.6	1.6	0.5
Operating expenses	4,602.2	3,266.5	2,919.4
Operating Income (Loss)	$ 7.6	$ 24.0	$ 56.1

Our Marketing business derives a majority of its operating income from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers requiring the natural gas. A majority of the natural gas we purchase is produced in Texas markets where we previously had limited physical access to the primary interstate pipeline delivery points, or hubs, such as the Houston Ship Channel. As a result of the completed segments of our natural gas system expansions and other initiatives during 2007 and 2008, our Marketing business now has access to several interstate natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

Our Marketing business is exposed to commodity price fluctuations because the natural gas purchased by our Marketing business is generally priced using an index that is different from the pricing index at which the gas is sold. This price exposure 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 volatility in the operating results of our Marketing segment.

In addition to the market access provided by our intrastate natural gas pipelines, our Marketing business also contracts for firm transportation capacity on third-party interstate and intrastate pipelines to allow access to additional markets. To offset the demand charges associated with these transportation agreements, 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 sales margin 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 these transportation agreements and limiting the Partnership’s exposure to cash flow volatility that could arise in markets where the transporting the natural gas becomes uneconomical. 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 with 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 all 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 our operating results.

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.

Year ended December 31, 2008 compared with year ended December 31, 2007

Operating income of our Marketing segment declined to $7.6 million for the year ended December 31, 2008 from income of $24.0 million for the corresponding period in 2007. Included in the operating income for the year ended December 31, 2008 are approximately $16.2 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, compared to the $3.8 million of unrealized mark-to-market losses for the comparable period of 2007. The unrealized, mark-to-market losses for the year ended December 31, 2008 result from decreases in the forward and daily market prices of natural gas from December 31, 2007. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

Operating income for the year ended December 31, 2008 was also negatively affected by non-cash charges of $7.5 million we recorded to reduce the cost basis of our natural gas inventory to net realizable value, which is $3.2 million more than the $4.3 million non-cash charge we recorded for the same period of 2007. Natural gas and NGL prices declined significantly from the record highs experienced in July of 2008. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

The operating and administrative expenses of our Marketing business are slightly more for the year ended December 31, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Marketing business has benefited from the increased access to preferred natural gas markets resulting from our natural gas system expansions and other initiatives. Although the operating income of our Marketing segment for the year ended December 31, 2007 of $24.0 million is $32.1 million lower than the $56.1 million for the year ended December 31, 2006, the change is primarily due to the $68.3 million decrease in unrealized, non-cash mark-to-market gains associated with our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. For the year ended December 31, 2007, we recorded $3.8 million of unrealized mark-to-market losses from our derivative activities as compared with $64.5 million of unrealized mark-to-market gains for the year ended December 31, 2006. The unrealized, mark-to-market losses for the year ended December 31, 2007, are the result of modest increases in the forward and daily market prices of natural gas from December 31, 2006. During the year ended December 31, 2006, declines in the forward and daily market prices of natural gas from the historically high prices existing at December 31, 2005 produced significant unrealized mark-to-market gains in our portfolio of derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. We expect the unrealized mark-to-market gains and losses associated with our portfolio of derivative financial instruments to be offset when the related physical transactions are settled. Refer to the discussions included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 15 to our Financial Statements beginning on page F-1 of this report).

The operating results of our Marketing business for the year ended December 31, 2007 also include gains of approximately $16.3 million that we realized upon the sale of natural gas inventory, including approximately $6.9 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory. Partially offsetting these gains are non-cash charges of $4.3 million that we recorded to reduce the cost basis of our natural gas inventory to net realizable value, which is $12.7 million less than the $17.0 million non-cash charges we recorded during the year ended December 31, 2006. The market price for natural gas in various storage locations may experience declines during the year from the prices at which the inventory was purchased. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

Corporate

Year ended December 31, 2008 compared with year ended December 31, 2007

Interest expense was $180.6 million for the year ended December 31, 2008, compared with $99.8 million for the corresponding period in 2007. The increases are primarily the result of a higher weighted average debt balance associated with the following debt issuances in 2008 and 2007:

- $500 million of our 9.875% Senior Notes in December 2008;
- $400 million of our 6.5% Senior Notes in April 2008;
- $400 million of our 7.5% Senior Notes in April 2008;
- $400 million of our Junior Subordinated Notes in September 2007; and
- $200 million of our Zero Coupon Senior Notes in August 2007.

Our weighted average interest rate is 6.4% for the year ended December 31, 2008 as compared with our weighted average interest rate of 6.1% for the same period in 2007.

Further contributing to the increase in interest expense is the $6.4 million decrease in interest capitalized to our construction projects for the year ended December 31, 2008 from the same period in 2007. For the year ended December 31, 2008 and 2007, our interest cost was comprised of the following:

	For the year ended December 31,	
	2008	2007
	(dollars in millions)	
Interest expense	$180.6	$ 99.8
Interest capitalized	41.0	47.4
Interest cost incurred	$221.6	$147.2
Interest paid	$193.1	$125.8

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. Beginning in 2006, two states (Michigan and Texas) enacted substantial changes to their tax structures to impose taxes that are based upon many but not all items included in net income. We report these taxes as income taxes under the provisions of SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109").

Our income tax expense is $7.0 million and $5.1 million for the years ended December 31, 2008 and 2007, respectively, which we computed by applying a 0.50% Texas state income tax rate to modified gross margin and a 0.10% Michigan state income tax rate to modified gross revenue. Our income tax expense represents a 1.7% and 2% effective rate as applied to pretax book income for December 31, 2008 and 2007, respectively.

Year ended December 31, 2007 compared with year ended December 31, 2006

Interest expense was $99.8 million in 2007 compared with $110.5 million in 2006. The decrease is due to $36.7 million of additional interest capitalized on our construction projects during the year compared with same period of 2006, partially offset by higher average debt balances and weighted average interest rates. Capitalized interest was approximately $47.4 million on our construction projects for 2007 compared with $10.7 million capitalized in 2006. Our weighted average interest rate was approximately 6.11% for the year ended December 31, 2007, compared with approximately 5.82% during 2006. Our debt balances are higher as a result of the capital expenditures we made to expand our pipeline systems that were partially financed by additional borrowings.

Our income tax expense of $5.1 million for the year ended December 31, 2007 results from the enactment, by the state of Texas, of a new state tax computed on our 2007 modified gross margin. No comparable tax existed during the year ended December 31, 2006. We determined this tax to be an income tax under the provisions of SFAS No. 109. We computed our income tax expense for the year ended December 31, 2007 by applying a 0.57% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents a 2% effective rate as applied to pretax book income.

LIQUIDITY AND CAPITAL RESOURCES

Impact of Current Economic Crisis

Multiple events during 2008, including a deep global recession that was largely precipitated by the financial sector of the global economy, have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators to provide liquidity, the capital markets currently remain constrained. As evidenced by our December 2008 debt offering, we have the ability to access the capital markets; however, the prices at which we can access capital are substantially higher than the prices we incurred for similar offerings in recent years. We expect our cost of capital to remain historically high over the next twelve months and possibly longer should capital markets remain constrained. As a result, we expect to selectively access the capital markets as necessary to fund our internal growth projects and maintain our investment grade credit rating.

Our near-term focus is to ensure we have sufficient liquidity to fund our growth programs and maintain our credit rating, while continuing the present distribution rate to our unitholders. The current economic crisis has created a challenging operating environment for us to maintain our liquidity and operating cash flows at levels consistent with the recent past while maintaining the present distribution rate to our unitholders.

We intend to move forward with our commercially supported internal growth projects, although our capital spending, particularly on the natural gas side of our business, will be reduced to minimize our capital raising requirements. Our ability to access the capital markets to fund new projects in the future at prices that make the proposed projects accretive is likely to be limited. We may revise the timing and scope of other projects as necessary to adapt to existing economic conditions and the incremental benefits expected to accrue to our unitholders from our expansion activities are likely to be decreased by substantial cost of capital increases during this period.

At December 31, 2008, we have in excess of $1.8 billion of liquidity to meet our ongoing operational and investment and finance needs, which we have determined as follows:

	2008
	(in millions)
Availability under Credit Facility	$ 998.9
Availability under Enbridge (U.S.) Credit Agreement	500.0
Cash and cash equivalents	339.9
Total	$1,838.8

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance activities, distributions to our partners and payments associated with our derivative activities. We expect to fund our current and future short-term cash requirements from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Our need for investment capital to fund our expansion projects, make acquisitions of new assets and businesses and to retire maturing or callable debt obligations is expected to be funded from several sources. We anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our Credit Facility, and from borrowings under our credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge and from other potential sources of capital. Likewise, we anticipate initially retiring our maturing and callable debt with similar borrowings on these existing facilities. We expect to obtain permanent financing through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. We have issued securities generating proceeds in excess of $4 billion over the past three years through the issuance of a balanced combination of debt and equity securities to fund our expansion projects. Our planned internal growth projects will require additional permanent capital and continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. Prevailing market conditions may limit our ability and willingness to complete future debt and equity offerings while the capital markets remain constrained and costs are high. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

The following table presents historical information about offerings of our limited partner interests since January 2006:

Issuance Date	Class of Limited Partnership Interest	Number of units Issued	Offering Price per unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)				
2008						
December[(3)]	Class A	16,250,000	$30.760	$499.6	$10.2	$509.8
March	Class A	4,600,000	49.000	217.2	4.6	221.8
2008 Totals		20,850,000		$716.8	$14.8	$731.6
2007						
May	Class A	5,300,000	$58.000	$301.9	$ 6.1	$308.0
April	Class C	5,930,792	53.113	314.4	6.4	320.8
2007 Totals		11,230,792		$616.3	$12.5	$628.8
2006						
August	Class C	10,869,565	$46.000	$500.0	$10.2	$510.2

(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.

(3) All Class A common units from the December 2008 issuance were issued to our General Partner.

In addition to the proceeds we have received from offerings of our limited partner interests, we have also generated additional equity capital from the in-kind distributions we have made to holders of our i-units and Class C units. The following table presents cash we have retained in our business since January 2006 from the in-kind distribution of additional i-units and Class C units:

Distribution Payment Date	Retained for i-units	Retained for Class C units	Retained from General Partner	Total Cash Retained
	(in millions)			
2008				
November 14	$14.3	$18.9	$0.7	$ 33.9
August 14	13.9	18.6	0.7	33.2
May 15	13.1	17.5	0.6	31.2
February 14	12.9	17.2	0.6	30.7
	$54.2	$72.2	$2.6	$129.0
2007				
November 14	$12.7	$16.8	$0.6	$ 30.1
August 14	12.1	16.2	0.6	28.9
May 15	11.9	15.9	0.6	28.4
February 14	11.7	10.2	0.5	22.4
	$48.4	$59.1	$2.3	$109.8
2006				
November 14	$11.5	$10.1	$0.4	$ 22.0
August 14	11.3	—	0.2	11.5
May 15	11.0	—	0.2	11.2
February 14	10.8	—	0.2	11.0
	$44.6	$10.1	$1.0	$ 55.7

Fixed income markets in the United States and around the world remain constrained due to insufficient liquidity and further deterioration in the global economy triggered by the unprecedented global economic conditions. Although the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations are considered "investment grade," we may at times experience difficulty accessing the long-term credit markets due to prevailing market conditions. Additionally, existing constraints in the credit markets may increase the rates we are charged for utilizing these markets.

Despite the current significant instability in the U.S. fixed income markets, we successfully raised net proceeds of $496.5 million in December 2008 through the issuance of $500 million in principal amount of our 9.875% senior unsecured notes due 2019. This issuance is discussed below and in Note 10 to our consolidated financial statements included in Item 8. Financial Statements of this Annual Report on Form 10-K

Notwithstanding the continuing weakness in the United States debt and equity markets, we expect to selectively access the capital markets as necessary to fund our internal growth projects on terms that are consistent with our financing objectives.

Available Credit

Historically our two primary sources of liquidity were the commercial paper market and our Credit Facility. We currently are effectively unable to access the commercial paper market due to a downgrade in our short-term credit rating by Standard and Poor's to A-3 from A-2 and are now utilizing our Credit Facility as our primary source of short-term liquidity. We use our Credit Facility primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions. In addition to our Credit Facility we have available a revolving credit agreement from Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge.

Outstanding Indebtedness

The following table presents the components of our outstanding indebtedness:

	December 31, 2008	
	2008	2007
	(in millions)	
Current maturities of long-term debt:		
9.150% First Mortgage Notes	$ 31.0	$ 31.0
4.000% Senior Notes due 2009	175.0	—
5.358% Senior unsecured zero coupon notes due 2022	214.7	—
	$ 420.7	$ 31.0
Long-term debt:		
Commercial paper	$ —	$ 268.5
Credit Facility	166.8	400.0
Affiliate Credit Agreement	—	—
9.150% First Mortgage Notes	62.0	93.0
4.000% Senior Notes due 2009	—	200.0
7.900% Senior Notes due 2012[1]	100.0	100.0
4.750% Senior Notes due 2013	200.0	200.0
5.350% Senior Notes due 2014	200.0	200.0
5.875% Senior Notes due 2016	300.0	300.0
7.000% Senior Notes due 2018[1]	100.0	100.0
6.500% Senior Notes due 2018	400.0	—
9.875% Senior Notes due 2019	500.0	—
7.125% Senior Notes due 2028[1]	100.0	100.0
5.950% Senior Notes due 2033	200.0	200.0
6.300% Senior Notes due 2034	100.0	100.0
7.500% Senior Notes due 2038	400.0	—
5.358% Senior unsecured zero coupon notes due 2022	—	203.6
8.050% Junior subordinated notes due 2067	400.0	400.0
Unamortized discount	(5.4)	(2.2)
	$3,223.4	$2,862.9
8.400% Note payable to affiliate[2]	$ 130.0	$ 130.0

(1) Debt of Enbridge Energy, Limited Partnership, one of our operating subsidiaries.
(2) Subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes.

Credit Facility

Our Credit Facility, as amended, is a revolving term facility that matures in April 2013. In April 2007, we entered into the Second Amended and Restated Credit Agreement which among other things increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion and allows us to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion through an accordion feature. We pay interest on the amounts outstanding at variable rates equal to a "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. We requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date of the Credit Facility from April 4, 2012 to April 4, 2013. We continue to use our Credit Facility to provide short-term financing for our operations and capital expansion programs.

In September 2008, following the bankruptcy filing by Lehman Brothers Holdings Inc. ("Lehman"), Lehman Brothers Bank, FSB ("Lehman BB") ceased to honor its funding commitment under the terms of our Credit Facility. Lehman BB has commitments to lend us up to $82.5 million under the terms of our Credit Facility. Since Lehman BB is no longer honoring our requests for funding, the amount available to us under our Credit Facility is effectively reduced to $1,167.5 million. In addition, Bank of America, N.A., as administrative agent to our Credit Facility, is requiring us to provide cash collateral for the portion of the letters of credit we have outstanding under the terms of our Credit Facility that would have been obligations of Lehman BB. At December 31, 2008, we had $0.1 million of cash collateral which is presented as "Restricted cash" on our consolidated statements of financial position. We may, from time to time, be required to provide additional cash collateral for letters of credit we have outstanding to support any funding requests for the portion of our Credit Facility not being funded by Lehman BB. Further, the maximum increase in principal amount of credit available to us that we can request through the accordion feature described above is also reduced to approximately $1.4 billion. The remaining lenders under our Credit Facility continue to honor our requests for funding and we believe the amounts available to us under our Credit Facility will continue to provide us with sufficient liquidity to meet our working capital needs.

At December 31, 2008, we had $166.8 million outstanding under our Credit Facility at a weighted average interest rate of 3.80% and letters of credit totaling $1.8 million. The amounts we can 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. Excluding the commitments from Lehman BB, at December 31, 2008, we could borrow $998.9 million under the terms of our Credit Facility, determined as follows:

	2008
	(in millions)
Total credit available under Credit Facility	$1,250.0
Less: Amounts outstanding under Credit Facility	(166.8)
Balance of letters of credit outstanding	(1.8)
Principal amount of commercial paper issuances	—
Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at December 31, 2008	$ 998.9

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.50 to 1.0 for periods ending on or before March 31, 2009; a ratio of 5.25 to 1.0 thereafter, for periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At December 31, 2008, our leverage ratio as defined under the Credit Facility was approximately 3.8. 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.

Commercial Paper Program

At December 31, 2008, we had no commercial paper outstanding, as we can effectively no longer access the commercial paper market due to a downgrade in our short-term credit rating by Standard & Poor's to A-3 from A-2 that occurred in November 2008. Under our commercial paper program, we had net repayments of approximately $268.0 million for the year ended December 31, 2008, which include gross issuances of $1,603.9 million and gross repayments of $1,871.9 million.

First Mortgage Notes

The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of Enbridge Energy, Limited Partnership, (the "OLP"), and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The First Mortgage Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness by the OLP, including compliance with certain debt issuance tests. We were in compliance with these covenants at December 31, 2008. We do not believe these issuance tests will negatively affect our ability to access the credit markets to finance future expansion projects. Under the First Mortgage Notes 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

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 structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $300 million of senior notes issued by the OLP (the "OLP Notes"). The borrowings under our Senior Notes are non-recourse to our general partner and Enbridge Management. All of our Senior Notes either pay or accrue 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. Our Senior 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, except in accordance with our indenture agreement. We were in compliance with these covenants at December 31, 2008.

The OLP, our operating subsidiary that owns the Lakehead system, has $300 million of senior notes outstanding representing unsecured obligations that are structurally senior to our Senior Notes. All of the OLP Notes pay interest semi-annually and have varying maturities and terms as set forth in the table above. The OLP Notes do not contain any covenants restricting us from issuing additional indebtedness by the OLP. The OLP Notes are subject to make-whole redemption rights and were issued under an indenture ("the OLP 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, except in accordance with the OLP Indenture. We were in compliance with these covenants at December 31, 2008.

In December 2008, we issued and sold $500 million in principal amount of our 9.875% senior notes due March 1, 2019. We granted the holders of our Senior Notes due 2019 an option to require us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100% of the principal amount of the notes tendered plus accrued and unpaid interest. We received net proceeds from the offering of approximately $496.5 million after underwriters' discounts and commissions, and payment of offering expenses. We used the proceeds to repay a portion of our outstanding Credit Facility borrowings that we use to finance our capital expansion projects and to repay $25 million of our Senior Notes maturing on January 15, 2009.

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 million in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.2 million after initial purchasers' discounts and payment of offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds which we later used to fund additional expenditures under our capital expansion programs. In August 2008, we completed the offers to exchange all of the Notes, which had not been registered under the Securities Act of 1933, as amended (the "Securities Act"), for notes with identical terms that had been registered under the Securities Act. We subsequently received tenders for $395 million in aggregate principal amount of our outstanding $400 million of 6.50% Series A Notes due 2018, which we exchanged for $395 million of our 6.50% Series B Notes due 2018. We also received tenders for all $400 million in aggregate principal amount of our 7.50% Series A Notes due 2038, which we exchanged for $400 million of our 7.50% Series B Notes due 2038.

In August 2007, we received net proceeds of approximately $200 million from a private placement of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes"), which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in long-term debt at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at December 31, 2007 includes $3.6 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called Zero Coupon Notes. The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to fund a portion of our capital expansion projects.

Junior Subordinated Notes

In September 2007, we issued and sold $400 million in principal amount of our 8.05% fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, which we refer to as the Junior Notes. We received net proceeds of approximately $393.0 million, after payment of underwriting discounts, commissions and offering expenses, which we used to temporarily reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we incurred to finance a portion of our capital expansion projects. The Junior Notes are subordinate in right of payment to all of our existing and future senior indebtedness, as defined in the related indenture.

Indebtedness to Affiliates

Hungary Note Payable

As of December 31, 2008 and 2007, we had $130.0 million in amounts outstanding under notes payable to Enbridge Hungary Ltd., an affiliate of our general partner (the "Hungary Note"). The Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. The Hungary Note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. The Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes.

EUS Credit Agreement

In December 2007, we entered an unsecured revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge ("EUS Credit Agreement"). Enbridge is the indirect owner of Enbridge Energy Company, Inc., our general partner. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2008, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

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, 2008:

	Standard & Poor's	Moody's	Dominion Bond Rating Service
Enbridge Energy Partners, L.P.			
Outlook	Negative	Negative	Negative
Corporate	BBB	Baa2	BBB
Commercial Paper	A-3	P-2	R-2(middle)
Medium Term Notes & Unsecured Debentures	BBB	Baa2	BBB
Junior subordinated debt	BB+	Baa3	BB(high)
Enbridge Energy, Limited Partnership			
Outlook	Negative	Negative	NR
Senior secured	BBB+	NR	NR
Senior unsecured	BBB	Baa1	NR

NR—No rating is available

Both S&P and Moody's continue to maintain our BBB and Baa2 rating, respectively, with negative outlooks. The negative outlooks reflect the credit agencies' views that our financial profile is weaker than those of our similarly rated peers but that this weaker financial profile is offset to a degree by our low business risk profile that stems from our highly regulated and/or contracted liquids and natural gas systems and our strategy of hedging a significant portion of our commodity exposure. Further, the negative outlooks reflect each credit rating agency's concern that our substantial organic growth capital expenditure program will place our financial profile under near term pressure until these projects are commissioned and increase our reliance on the capital markets to access the necessary capital. Both credit rating agencies believe that completion of our organic growth projects should contribute to a further reduction in our overall business risk profile and that the cash flow generated by these projects as they are commissioned will strengthen our financial profile. Following the successful execution of both the construction and financing of these growth projects, an improved rating outlook by Moody's is possible.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2008:

	2009	2010	2011	2012	2013	Thereafter	Total
				(in millions)			
Long-term debt and notes payable to affiliates	$420.7	$31.0	$31.0	$600.0	$366.8	$2,330.0	$3,779.5
Purchase commitments(1)	299.3	—	—	—	—	—	299.3
Power commitments(2)	2.1	—	—	—	—	—	2.1
Other operating leases	12.0	10.2	10.1	9.7	9.9	63.2	115.1
Right-of-way(3)	1.9	1.8	1.8	1.8	1.7	43.2	52.2
Product purchase obligations(4)	29.2	32.6	33.1	32.9	32.4	65.6	225.8
Service contract obligations(5)	27.8	22.9	20.7	10.2	1.5	—	83.1
Total	$793.0	$98.5	$96.7	$654.6	$412.3	$2,502.0	$4,557.1

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion projects.

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to be approximate $1.7 million to $1.9 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2013.

(4) 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.

(5) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

The payments made under our obligations and commitments for the years ended December 31, 2008, 2007 and 2006 were $947.1 million, $822.5 million and $222.4 million, respectively.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next two years for the construction of additional natural gas and crude oil transportation infrastructure. Anticipated growth in western Canadian oil sands production and the need to reach newer markets has prompted the Southern Access, Alberta Clipper and related projects associated with our liquid systems. In 2009, we expect to spend approximately $1.6 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed into service. At December 31, 2008, we had approximately $299.3 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2009.

Forecasted Expenditures

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 include our capital expansion projects and other projects that 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.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2009. Although we anticipate making the expenditures in 2009, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program. We made capital expenditures of $1,375.4 million, including $62.1 million on core maintenance activities, for the year ended December 31, 2008.

For the full year ending December 31, 2009, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in billions)
System enhancements	$0.4
Core maintenance activities	0.1
Southern Access expansion	0.2
Alberta Clipper	0.9
	$1.6

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through December 31, 2008, the incremental capacity that will or has become available upon completion of the project and the periods we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures			
	Estimated Total Cost	Actual Expenditures through December 31, 2008	Estimated Incremental Capacity Oil	Expected Completion
	(in billions)		(Kbpd)	
Southern Access expansion (Lakehead)	$2.1	$1.9	400	2009
Alberta Clipper	1.2	0.1	450	Mid-2010
North Dakota phase 6 expansion	0.2	—	50	Early 2010
Total	$3.5	$2.0	900	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next year due to our Southern Access expansion and Alberta Clipper 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 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.

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 ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing. In the current environment acquisitions are unlikely and 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.

Derivative Activities

We use derivative financial instruments (e.g., 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 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 based upon the market values at December 31, 2008 for each of the indicated calendar years:

	Notional	2009	2010	2011	2012	2013	Total
			(dollars, in millions)				
Swaps							
Natural gas[1]	287,506,513	$(38.3)	$(31.6)	$(28.8)	$ (7.1)	$2.0	$(103.8)
NGL[2]	6,547,837	63.5	26.7	12.7	14.8	—	117.7
Crude[2]	1,390,000	5.2	5.0	2.5	0.8	3.4	16.9
Options—calls							
Natural gas[1]	1,095,000	(0.6)	(1.0)	(1.0)	—	—	(2.6)
Options—puts							
Natural gas[1]	359,587	(1.2)	—	—	—	—	(1.2)
NGL[2]	858,832	9.3	5.2	2.7	4.4	—	21.6
Totals		$ 37.9	$ 4.3	$(11.9)	$12.9	$5.4	$ 48.6

(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 our operating activities was $543.3 million in 2008 compared with $463.4 million in 2007. The increase in operating cash flow is directly attributable to the improved operating performance of our Liquids and Natural Gas systems. Although net cash provided by operating activities increased, cash flows associated with changes in our working capital accounts for the year ended December 31, 2008 were lower than the same period of 2007 due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2008 was $1,428.3 million, a decrease of $336.7 million from the $1,765 million used during the same period of 2007. The decrease is primarily attributable to the $481.2 million reduction of amounts spent in 2008 on our construction projects as compared to the same period of 2007. The decrease in the amounts spent on our construction projects is primarily attributable to completion of our Clarity project and the first stage of our Southern Access expansion project. This decrease is partially offset by $133 million of proceeds we received from the sale of our KPC system that occurred in 2007. A similar transaction was not present in 2008. We expect that cash flows used in our investing activities will remain at high levels throughout the periods we are performing extensive expansions to our Lakehead system.

Financing Activities

Net cash provided by financing activities during the year ended December 31, 2008 was $1,174.4 million, an increase of $6.9 million from the $1,167.5 million generated during the year ended December 31, 2007. Net cash provided by financing activities for the year ended December 31, 2008 is attributable to the following:

- $221.8 million we raised in March 2008 from the issuance of 4.6 million class A common units, which consisted of $217.2 million of net proceeds after payment of underwriters' discounts, commissions and offering expenses, and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest.
- In early April 2008, we completed the private issuance and sale of our 6.50% $400 million senior notes due 2018 and our 7.50% $400 million senior notes due 2038 for net proceeds of approximately $790.2 million, after payment of initial purchasers' discounts, underwriters' discounts and commissions and offering expenses.
- $509.8 million we raised in December 2008 from the private issuance of 16.25 million class A common units to our general partner, which consisted of $499.6 million of net proceeds after offering expenses, and a contribution of $10.2 million from our general partner to maintain its two percent general partner interest.
- In December 2008, we completed the public issuance and sale of our 9.875% $500 million senior notes due 2019 for net proceeds of approximately $496.5 million, after payment of underwriters' discounts and commissions and offering expenses.

The increase in cash raised from both our unit and debt issuances is partially offset by the following:

- $501.2 million of net repayments on our Credit Facility and commercial paper; and
- $41.3 million more distributions to our partners in 2008 compared to the same period in 2007 due to a greater number of units outstanding, a higher distribution level and higher incentive distribution payments to our general partner.

Cash Distributions

We make quarterly distributions to our General Partner and the holders of our limited partner units in an amount equal to our "available cash." As defined in our partnership agreement, "available cash" represents 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. We retain reserves to provide for the proper conduct of our business, to stabilize distributions to our 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.

As the owner of our i-units, Enbridge Management does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B 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 sum of Enbridge Management's shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per limited partner 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.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our Class A and Class B common units, which we collectively refer to as common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the New York Stock Exchange for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units will increase automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

After August 15, 2009, subject to conditions set forth in our partnership agreement, our Class C units will convert into Class A common units on a one-for-one basis and will receive quarterly cash distributions equal to those paid to the holders of our common units. If our Class C units are not converted, the holders of our Class C units will receive quarterly cash distributions equal to 115 percent of those paid to the holders of our common units. Prior to conversion, holders of our Class C units will not be entitled to receive any quarterly cash distributions until the holders of our common units have received a quarterly cash distribution of $0.59 per common unit.

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units and Class C 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 and holders of our Class C units will not receive cash. We retain the cash for use in our operations to finance a portion of our capital expansion projects. During 2008, we distributed a total of 1,198,969 i-units through quarterly distributions to Enbridge Management, compared with 889,938 in 2007. Additionally, in 2008 we distributed a total of 1,615,601 Class C units to the holders of our Class C units compared with 1,072,423 in 2007. We retained $126.4 million, $107.5 million, and $54.7 million in 2008, 2007, and 2006, respectively, related to the i-unit and Class C unit distributions.

Our current annual cash distribution rate is $3.96 per unit, or $0.990 per quarter compared with $3.88 for the year ended December 31, 2008. 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 or use cash retained by issuance of payment in-kind distributions for the purpose of paying cash distributions. We may do this until we realize the full impact of assets being developed on operations or to respond to expected short-term aberrations in our performance caused by market disruption events or depressed commodity prices. We expect that our major capital expansion projects will be accretive to distributable cash flow when they are completed and operational. As a result of current economic conditions and the rapid decrease in commodity prices, our objective is to maintain our current distribution in 2009.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements.

Subsequent Events

UTOS Disposition

In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), LLC, a wholly-owned subsidiary of Enbridge. 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 contracts. The UTOS system was not considered strategic to the ongoing operations of the Partnership, but is strategically aligned with Enbridge's offshore operations.

Distribution to Partners

On January 30, 2009, the board of directors of Enbridge Management declared a distribution payable to our partners on February 13, 2009. The distribution was paid to unitholders of record as of February 5, 2009, of our available cash of $128.0 million at December 31, 2008, or $0.990 per limited partner unit. Of this distribution,

$93.2 million was paid in cash, $14.6 million was distributed in i-units to our i-unitholder, $19.5 million was distributed in Class C units to the holders of our Class C units and $0.7 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

Regulatory—North Dakota Tariff Filing

Effective January 1, 2009, we increased our rates for transportation on our North Dakota System to include an updated calculation of the two surcharges relating to the Phase V Expansion program. These surcharges are applicable for the five years immediately following the in-service date of the Phase V Expansion program, which was placed in service in January 2008. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originating at Trenton and Alexander, North Dakota. The rates and surcharges for transportation of light crude oil to principle delivery points via trunk lines on the Enbridge North Dakota System are set forth below:

	Indexed Base Rate per Barrel	Phase V Surcharge Per Barrel	Published Rate per Barrel FERC No. 59[(1)]
From Glenburn, Haas, Lignite, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$0.8120	$0.1758	$0.9878
From Brush Lake to Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	0.9298	0.1758	1.1056
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to Clearbrook, Minnesota	0.9558	0.1758	1.1316
From Tioga, North Dakota to Clearbrook, Minnesota	0.8379	0.1758	1.0137
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	1.0609	0.8714	1.9323
From Alexander, North Dakota to Clearbrook, Minnesota	1.1000	0.8714	1.9714
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5108	—	0.5108
From Reserve, Montana to Tioga, North Dakota	0.5762	—	0.5762
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	0.4847	0.6956	1.1803
From Alexander, North Dakota to Clearbrook, Minnesota	0.5235	0.6956	1.2191

(1) Pursuant to FERC Tariff No. 59 as filed with the FERC on December 1, 2008, with an effective date of January 1, 2009.

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 Estimation of Revenues and Cost of Natural Gas

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectability is reasonably assured. For our natural gas and marketing businesses, 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 period reported. We believe that the assumptions underlying these estimates will not be significantly different from the actual amounts due to the routine nature of these estimates and the consistency 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 replaced, improved, or the useful lives have been extended; 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 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.

Regulatory guidance issued by the FERC requires 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 adopted this guidance prospectively in January 2006 for all our pipeline systems. 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 continue to be capitalized. We typically expense the cost of initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects consistent with industry practice and the regulatory guidance issued by the FERC. However, we capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis 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 stand-alone pipeline system is 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, 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 as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals 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. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. 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 allocated to two of our segments, Natural Gas and Marketing.

Pursuant to the provisions of SFAS No. 142, *"Goodwill and Other Intangible Assets,"* we do not amortize goodwill, but test it 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 be impaired. In testing goodwill for impairment, we make critical assumptions that include but are not limited to: 1) projections of future financial performance, which include commodity price and volume assumptions, 2) the expected growth rate of our Natural Gas and Marketing assets, 3) residual value of the assets and 4) our weighted average cost of capital. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value of goodwill. At the time we determine that an impairment has occurred, we will reduce the carrying value of goodwill to its fair value.

Our intangible assets consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our 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 and its carrying amount exceeds its fair value, the intangibles are written down to their fair value.

Fair Value Measurements

We adopted prospectively the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. We define fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We employ a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those assets and liabilities that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources. (i.e., values supported by lesser volumes of market activity).

We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include debt and derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value; however, the cost of obtaining the information is prohibitive.

The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third party investment dealers who actively make markets in our debt securities, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. Our assets are adjusted for the non-performance risk of our counterparties using their credit default swap spread rates, which are updated quarterly. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and are also adjusted quarterly based on current default swap spread rates on our outstanding indebtedness. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Our derivative contracts can be exchange-traded or over-the counter (“OTC”). We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of our fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to lacking binding broker quotes to corroborate pricing data. Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or we revise our interpretation of Level 2 criteria in practice to include non-binding market corroborated data.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. In accordance with Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (“SFAS No. 133”), we record all derivative financial instruments on our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under SFAS 133, the accounting treatment depends on the intended use and designation of each instrument. 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 fair market value is recorded as a component of "Interest expense" in the consolidated statements of income. We have hedged a portion of our exposure to the variability in future cash flows associated with forecasted natural gas and NGL sales and purchases through 2013 in accordance with our risk management policies.

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by 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 or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment that we use are cash flow hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

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, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations 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.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges 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 fair market value is recognized immediately in earnings. We determine the change in fair market value of financial instruments designated and qualifying as fair value hedges each period which we record in earnings. In addition, we calculate the change in the fair market value of the hedged item which is also recorded in 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 use of the mark-to-market method of accounting as required under GAAP for derivative financial instruments that do not qualify for hedge accounting. We use short-term, highly liquid derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments do not qualify for hedge accounting treatment under SFAS No. 133, and as a result we record changes in fair value of these instruments on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying indices, primarily commodity prices.

Asset Retirement Obligations

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. 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 the cost of abandoning or retiring a pipeline system. 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 consumption of those resources by end users. 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 record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value 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 ARO 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 an ARO when assets are taken out of service or otherwise abandoned.

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 in "Accounts payable and other" and "Other long-term liabilities" in the statements of financial position 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. We typically expense legal costs associated with loss contingencies as such costs are incurred.

Crude Oil Over/Short Balance and Crude Oil Measurement Gains/Losses

Crude oil over/short balance and crude 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 crude oil measurement gains/losses and our crude 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 crude oil over/short balance or revision of our crude oil measurement gain/loss estimates. We include the crude oil measurement gains/losses in our operating and administrative expenses on our consolidated statements of income and the crude 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

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 "Accrued receivables" and "Accrued purchases" on our consolidated statements of financial position using the posted index prices, which approximate market rates, or our weighted average cost of gas.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Derivative Instruments and Hedging Activities

In March 2008, the FASB issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We did not adopt the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF, reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share.* Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We do not expect the adoption of the pronouncement to have a significant effect on our computation of earnings per unit per limited partner.

Business Combinations

In December 2007, the Financial Accounting Standards Board, or FASB, issued Statement No. 141(R), *Business Combinations*, which we refer to as SFAS No. 141(R). The new standard retains the fundamental requirements in FASB Statement No. 141, *Business Combinations*, that the acquisition method of accounting (previously referred to as the *purchase method*), be used for all business combinations and for an acquirer to be identified for each business combination. Among other items, SFAS No. 141(R) requires the following:

- Assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date are to be measured at their fair values as of that date.
- Costs associated with effecting an acquisition and restructuring costs the acquirer was not obligated to incur are recognized separately from the business combination.

- Assets acquired and liabilities assumed arising from contractual contingencies as of the acquisition date are measured at their acquisition-date fair values.
- Noncontractual contingencies as of the acquisition date are measured at the acquisition-date fair values only if it is more likely than not that they meet the definition of an asset or liability in FASB Statements of Financial Accounting Concepts ("SFAC") Statement No. 6, *Elements of Financial Statements*.
- Assets and liabilities arising from contingencies are to be reported at the acquisition-date fair value absent new information about the possible outcome, however, when new information becomes available, liabilities are measured at the higher of the acquisition date fair value or the FASB Statement No. 5, *Accounting for Contingencies* ("SFAS No. 5") amount while assets are measured at the lower of the acquisition date fair value or the best estimate of the future settlement amount.
- Goodwill as of the acquisition date is determined as the excess of the fair value of the consideration transferred plus the fair value of any noncontrolling interest plus the fair value of previously held equity interests less the fair values of the identifiable net assets acquired.
- Recognition of a gain in earnings attributable to the acquirer when the total acquisition date fair value of the identifiable net assets acquired exceed the fair value of the consideration transferred plus any noncontrolling interest in the acquiree.
- Contingent consideration at the acquisition date is measured at its fair value at that date.
- Retroactively recognize adjustments made during the measurement period (not more than one year from the acquisition date) as if the accounting had occurred on the acquisition date.

SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and early adoption is not permitted. The provisions of this statement will require us to expense certain costs associated with acquisitions that were previously permitted to be capitalized which may affect our operating results in periods that we complete an acquisition.

Noncontrolling Interests

In December 2007, the FASB issued Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* ("SFAS No. 160"), to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for deconsolidation of a subsidiary. Among other provisions, SFAS No. 160 requires the following:

- The ownership in subsidiaries held by parties other than the parent be presented in the consolidated statement of financial position within equity, but separate from the parent's equity.
- The amount of consolidated net income attributable to the parent and the noncontrolling interest be presented on the face of the consolidated statement of income.
- Changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary are accounted for as equity transactions.
- Any retained noncontrolling equity investment in a subsidiary that is deconsolidated be initially measured at fair value.
- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

SFAS No. 160 is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2008, and early adoption is prohibited. SFAS No. 160 requires prospective adoption as of the beginning of the fiscal year in which the provisions are initially applied, except for the presentation and disclosure requirements which shall be applied retrospectively for all periods presented. Our adoption of this standard will not have a material effect on our financial position or results of operations.

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. 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 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 following table presents the principal cash flows and related weighted average interest rates by expected maturity dates along with the carrying values and fair values of our third-party debt obligations as of December 31, 2008 and 2007.

	December 31, 2008									December 31, 2007	
	Average Interest Rate	Expected Maturity of Carrying Amounts by Fiscal Year									
		2009	2010	2011	2012	2013	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
	(dollars in millions)										
Fixed Rate:											
First Mortgage Notes	9.150%	$ 31.0	$31.0	$31.0	$ —	$ —	$ —	$ 93.0	$ 93.8	$124.0	$135.1
Senior Notes due 2009	4.000%	175.0	—	—	—	—	—	175.0	175.2	200.0	198.5
Senior unsecured zero coupon notes due 2022	5.358%	214.7	—	—	—	—	—	214.7	211.0	203.6	210.7
Senior Notes due 2012	7.900%	—	—	—	99.9	—	—	99.9	93.7	99.9	110.2
Senior Notes due 2013	4.750%	—	—	—	—	199.9	—	199.9	163.4	199.8	192.0
Senior Notes due 2014	5.350%	—	—	—	—	—	199.9	199.9	151.3	199.9	194.3
Senior Notes due 2016	5.875%	—	—	—	—	—	299.8	299.8	234.5	299.7	293.7
Senior Notes due 2018	7.000%	—	—	—	—	—	99.9	99.9	81.9	99.9	105.3
Senior Notes due 2018	6.500%	—	—	—	—	—	398.0	398.0	317.7	—	—
Senior Notes due 2019	9.875%	—	—	—	499.7	—	—	499.7	500.4		
Senior Notes due 2028	7.125%	—	—	—	—	—	99.8	99.8	72.7	99.8	104.3
Senior Notes due 2033	5.950%	—	—	—	—	—	199.7	199.7	119.7	199.7	176.9
Senior Notes due 2034	6.300%	—	—	—	—	—	99.8	99.8	62.3	99.8	92.1
Senior Notes due 2038	7.500%	—	—	—	—	—	398.9	398.9	289.2	—	—
Junior subordinated notes due 2067	8.050%	—	—	—	—	—	399.3	399.3	209.3	399.3	385.9
Variable Rate:											
Commercial paper	—	—	—	—	—	—	—	—	—	268.5	268.5
Credit Facility	3.800%	—	—	—	—	166.8	—	166.8	166.8	400.0	400.0

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. 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. 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 risks associated with market fluctuations in 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 forecasted transaction and are not entered into with the objective of speculating on interest rates.

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations which are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. 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. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2008.

	December 31, 2008									December 31, 2007		
	Expected Maturity of Carrying Amounts by Fiscal Year											
								Fair Value			Fair Value	
	Notional Amount	2009	2010	2011	2012	2013	Thereafter	Asset	Liability	Notional Amount	Asset	Liability
	(dollars in millions)											
Interest Rate Derivatives												
Interest Rate Swaps:												
Floating to Fixed	$ 325.0	$ (4.3)	$ (3.5)	$ (2.6)	$ (2.2)	$ (0.9)	$—	$ —	$(13.5)	$ 325.0	$ —	$(3.0)
Average Pay Rate	4.36%	4.39%	4.35%	4.35%	4.35%	4.35%	—	—	—	4.41%	—	—
Average Receive Rate	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	—	—	—	LIBOR-0.21%	—	—
Fixed to Floating	$ 125.0	$ 4.5	$ 4.0	$ 3.1	$ 2.7	$ 1.0	$—	$15.3	$ —	$ 125.0	$4.1	$ —
Average Pay Rate	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	—	—	—	LIBOR-0.21%	—	—
Average Receive Rate	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	—	—	—	4.75%	—	—
Treasury Locks												
Floating to Fixed	$ —	$ —	$ —	$ —	$ —	$ —	$—	$ —	$ —	$ 200.0	$ —	$(8.3)
Average Pay Rate	—	—	—	—	—	—	—	—	—	4.04%	—	—
Average Receive Rate	—	—	—	—	—	—	—	—	—	10YR-UST	—	—
Interest Rate Collars												
Calls	$ —	$ —	$ —	$ —	$ —	$ —	$—	$ —	$ —	$ 100.0	$ —	$ —
Average Pay Rate	—	—	—	—	—	—	—	—	—	5.50%	—	—
Average Receive Rate	—	—	—	—	—	—	—	—	—	LIBOR	—	—
Puts	$ —	$ —	$ —	$ —	$ —	$ —	$—	$ —	$ —	$ 100.0	$ —	$ —
Average Pay Rate	—	—	—	—	—	—	—	—	—	4.17%	—	—
Average Receive Rate	—	—	—	—	—	—	—	—	—	LIBOR	—	—

(1) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

(2) UST refers to United States Treasury notes.

Our short-term floating to fixed rate interest rate swaps with the exception of the contract maturing February 13, 2009, qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on $150 million of our variable rate indebtedness. As such, the fair values of these derivative financial instruments are recorded as assets and liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in “Accumulated other comprehensive income,” or AOCI. We discontinued hedge accounting treatment in December 2008 for our floating to fixed rate interest rate swap maturing February 13, 2009 originally hedging $50 million of our variable rate indebtedness when we reduced the balance of our Credit Facility below $200 million. As such, changes in the fair value of this derivative financial instrument are recorded in earnings as an increase or decrease in “Interest expense.”

The long-term floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 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 subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). 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 manage the risks associated with market fluctuations in commodity prices, as well as reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted 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, 2008 and December 31, 2007, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	December 31, 2008						December 31, 2007	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	24,294,043	$ 5.24	$ 7.42	$ 2.5	$(56.0)	$5.5	$ (1.6)
	NGL	176,870	26.61	63.69	—	(6.5)	—	—
Receive fixed/pay variable	Natural Gas	23,840,879	6.48	5.69	38.7	(19.6)	1.2	(41.8)
	NGL	3,735,045	46.19	27.33	70.0	—	—	(43.6)
	Crude Oil	354,625	69.29	54.47	5.8	(0.6)	—	(7.2)
Receive variable/pay variable	Natural Gas	129,423,183	5.49	5.52	8.9	(12.8)	2.9	(1.8)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.10	—	(0.6)	—	(1.5)
Puts (written)	Natural Gas	359,587	5.79	9.22	—	(1.2)	—	—
Puts (purchased)	NGL	474,500	46.24	27.33	9.3	—	0.6	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	3,836,409	$ 6.53	$ 7.59	$ 2.5	$ (6.5)	$4.4	$ —
	NGL	45,625	28.94	57.63	—	(1.3)	—	—
Receive fixed/pay variable	Natural Gas	10,171,510	4.45	6.98	2.2	(27.5)	—	(38.0)
	NGL	1,513,655	49.12	30.24	28.0	—	—	(13.8)
	Crude Oil	332,150	79.29	63.89	5.5	(0.5)	—	(4.4)
Receive variable/pay variable	Natural Gas	64,490,495	6.84	6.88	0.8	(3.1)	1.5	(0.7)
Options								
Calls (written)	Natural Gas	365,000	4.31	7.13	—	(1.0)	—	(1.4)
Puts (purchased)	NGL	172,280	59.23	29.52	5.2	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	2,495,560	$ 6.96	$ 7.29	$ 2.6	$ (3.4)	$3.2	$ —
Receive fixed/pay variable	Natural Gas	8,852,725	4.06	7.23	1.1	(28.1)	—	(34.1)
	NGL	581,810	55.84	33.02	13.0	(0.3)	—	(4.3)
	Crude Oil	410,625	75.11	68.82	3.3	(0.8)	—	(3.4)
Receive variable/pay variable	Natural Gas	15,885,000	7.27	7.34	—	(1.0)	0.1	—
Options								
Calls (written)	Natural Gas	365,000	4.31	7.31	—	(1.0)	—	(1.4)
Puts (purchased)	NGL	83,220	63.34	30.83	2.7	—	—	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	941,709	$ 7.16	$ 8.72	$ 0.8	$ (2.1)	$0.9	$ —
	NGL	36,600	30.47	55.58	—	(0.9)	—	—
Receive fixed/pay variable	Natural Gas	1,456,000	3.57	7.78	—	(5.8)	—	(6.8)
	NGL	458,232	70.56	33.92	15.7	—	—	—
	Crude Oil	219,600	74.85	71.09	0.8	—	—	(1.9)
Receive variable/pay variable	Natural Gas	1,089,000	6.71	6.67	—	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	32.19	4.4	—	—	—
Contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.86	$ 2.0	$ —	$ —	$ —
	Crude Oil	73,000	124.05	72.71	3.4	—	—	—

(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, 2008 and December 31, 2007, 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.

We record all derivative financial instruments in our consolidated financial statements at fair market value which we adjust 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, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in Cost of natural gas for our commodity-based derivatives and Interest expense for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income ("AOCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. 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 hedges and qualify for hedge accounting are included in Cost of natural gas for commodity hedges and Interest expense for interest rate hedges in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued, remain in AOCI 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. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, 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 hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain or 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 or 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 on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge 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 four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included 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 the associated financial instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

2. **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

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 cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. 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 being marked-to-market, 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.

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural

gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

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 or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) 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.

We routinely enter into interest rate swaps to fix the interest rates associated with our variable rate debt, including commercial paper and bank borrowings. In August 2007, we entered into forward-starting interest rate swaps that we designated as cash flow hedges of variable rate debt to begin in October 2007 and November 2007. The specific floating rate borrowings did not take place as initially forecast; thereby causing the interest rates swaps to no longer qualify as cash flow hedges. As a result, we recorded a charge to interest expense of $1.4 million, representing the fair market value of the interest rate swaps at December 31, 2007. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of cost of natural gas and interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the year ended December 31,		
	2008	2007	2006
	(in millions)		
Natural Gas segment			
Hedge ineffectiveness	$ (0.1)	$ —	$ (1.9)
Non-qualified hedges	85.1	(59.0)	1.8
Marketing			
Non-qualified hedges	(16.2)	(3.8)	64.5
Commodity derivative fair value gains (losses)	68.8	(62.8)	64.4
Corporate			
Non-qualified interest rate hedges	—	(1.4)	—
Derivative fair value gains (losses)	$ 68.8	$ (64.2)	$ 64.4

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2008	2007
	(in millions)	
Other current assets	$ 70.6	$ 6.5
Other assets, net	75.7	6.4
Accounts payable and other	(40.6)	(165.5)
Other long-term liabilities	(71.0)	(192.9)
	$ 34.7	$ (345.5)

The net assets associated with derivative activities are primarily due to the decrease in current and forward natural gas and NGL prices from December 31, 2007 to December 31, 2008. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $1.5 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2008, 2007 and 2006, we reclassified unrealized losses of $140.5 million, $94.8 million and $78.3 million, respectively, from AOCI to cost of natural gas on our consolidated statements of income for the fair value of derivative financial instruments that were settled.

In connection with our April 2008 issuances and sales of our $400 million in principal amount of 6.50% senior notes due April 15, 2018 and $400 million in principal amount of our 7.50% senior notes due April 15, 2038, we paid $22.1 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the senior notes maturing in 2038. The $22.1 million is being amortized from AOCI to "Interest expense" over the 30-year term of the senior notes.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2008	2007
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(39.6)	(298.3)
A	73.3	(47.2)
Lower than A	(1.2)	—
	32.5	(345.5)
Credit valuation adjustment	2.2	—
Total	$ 34.7	$(345.5)

* As determined by nationally recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to decreases in forward commodity prices, we continue to closely monitor our outstanding financial exposure. When credit thresholds are met pursuant to the terms of our International Securities Dealers Association ("ISDA") financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

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

We 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. Our management has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2008. 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, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual 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, 2008, 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, 2008.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting as of December 31, 2008, beginning on page F-2.

Changes in Internal Control Over Financial Reporting

No changes in our internal control over financial reporting were made during the three months ended December 31, 2008, that would materially affect our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

We are a limited partnership and have no officers or directors of our 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 us, 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
Directors and Executive Officers:		
Martha O. Hesse	66	Director and Chairman of the Board
Jeffrey A. Connelly	62	Director
George K. Petty	67	Director
Dan A. Westbrook	56	Director
Stephen J.J. Letwin	53	Managing Director and Director
Terrance L. McGill	54	President and Director
Stephen J. Wuori	51	Executive Vice President—Liquids Pipelines and Director
Officers:		
Richard L. Adams	44	Vice President—U.S. Engineering and Project Execution, Liquids Pipelines
E. Chris Kaitson	52	Vice President—Law and Deputy General Counsel
Douglas V. Krenz	57	Vice President
John A. Loiacono	46	Vice President—Commercial Activities
Mark A. Maki	44	Vice President—Finance
Al Monaco	49	Executive Vice President—Major Projects
Stephen J. Neyland	41	Controller
Kerry C. Puckett	47	Vice President—Engineering and Operations, Gathering and Processing
Jonathan N. Rose	41	Treasurer
Allan M. Schneider	50	Vice President—Regulated Engineering and Operations, Gathering and Processing
Bruce A. Stevenson	53	Corporate Secretary
Leon A. Zupan	53	Vice President—Liquids Pipelines Operations

Martha O. Hesse was elected as Chairman of the Board in May 2007 and as a director of the General Partner and Enbridge Management in March 2003 and serves as a member of the Audit, Finance & Risk Committee. Ms. Hesse was President and Chief Executive Officer 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 is a private investor and currently serves as a director of AMECplc, Mutual Trust Financial Group, and Terra Industries, Inc.

Jeffrey A. Connelly was elected a director of the General Partner and Enbridge Management in January 2003 and serves as the Chairman of the 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.

George K. Petty was elected a director of the General Partner in February 2001 and Enbridge Management upon its formation and serves on the 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 retired in 1994 from AT&T Corporation as a Vice-President after 25 years of service. He currently serves on the Board of Directors of Fuelcell Energy Corporation.

Dan A. Westbrook was elected a director of the General Partner and Enbridge Management in October 2007 and serves on the Audit, Finance & Risk Committee. In 2008 he joined the Board of Directors of the Carrie Tingley Hospital Foundation. From May 2007 until August 2008 he has served on the Board of Directors of Synenco Energy Inc. where he was a member of the their Audit & Risk and Finance Committees, until being acquired by Total E&P Canada. From January 2006 until May 2008, he served on the Board of Directors of Knowledge Systems Inc., a privately held U.S. company prior to its acquisition by Halliburton. From 2001 to 2005 Mr. Westbrook served as President of BP China Gas, Power & Upstream and Vice-Chairman of the Board of Directors of Dapeng LNG, a Sino joint venture between BP subsidiaries and other Chinese companies. From 1999 to 2001 Mr. Westbrook was the Associate President with BP in Argentina. Prior to that he held executive positions with BP in Houston, Russia, Chicago, and The Netherlands.

Stephen J.J. Letwin was elected Managing Director of the General Partner and Enbridge Management in May 2006, and is also Executive Vice President, Gas Transportation & International of Enbridge. Prior to his election he served Enbridge, the indirect parent of our General Partner, as Group Vice President, Gas Strategy & Corporate Development from April 2003; prior thereto he served Enbridge as Group Vice President, Distribution & Services from September 2000.

Terrance L. McGill was elected President of the General Partner and Enbridge Management in May 2006. Mr. McGill previously served as Vice President, Commercial Activity and Business Development of the General Partner and Enbridge Management from April 2002 and Chief Operating Officer from July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

Stephen J. Wuori was elected a director of the General Partner and Enbridge Management in January 2008 and is also the Executive Vice President of Liquids Pipelines for the General Partner and Enbridge Management. Mr. Wuori holds similar responsibilities with Enbridge. He was previously Executive Vice President, Chief Financial Officer and Corporate Development of Enbridge from 2006 to 2008, Group Vice President and Chief Financial Officer of Enbridge from 2003 to 2006 and Group Vice President, Corporate Planning and Development of Enbridge from 2001 to 2003.

Richard L. Adams was elected Vice President, U.S. Engineering and Project Execution, Liquids Pipelines of the General Partner and Enbridge Management in June 2007 prior to which he was Vice President, Operations and Technologies from April 2003. Prior to April 2003, he was Director of Technology & Operations for the General Partner and Enbridge Management from 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for Ocensa/Enbridge in Bogota, Colombia from 1997 to 2001.

E. Chris Kaitson was elected Vice President, Law and Deputy General Counsel of the General Partner and Enbridge Management in May 2007. He also currently serves as Deputy General Counsel of Enbridge. Prior to that he was Assistant General Counsel and Assistant Secretary of the General Partner and Enbridge Management from July 2004. He served as Corporate Secretary of the General Partner and Enbridge Management from October 2001 to July 2004. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until acquired by Enbridge in May 2001.

Douglas V. Krenz was elected Vice President of the General Partner and Enbridge Management 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.

John A. Loiacono was elected Vice President, Commercial Activities, of the General Partner and Enbridge Management in July 2006. Prior to that, he was Director of Commercial Activities for the General Partner and Enbridge Management from April 2003 and commenced employment with Midcoast Energy Resources in February 2000 as an Asset Optimizer.

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

Al Monaco was elected Executive Vice President, Major Projects of the General Partner and Enbridge Management in January 2008 and holds similar responsibilities with Enbridge. Prior to that Mr. Monaco was President of Enbridge Gas Distribution Inc. from September 2006, Senior Vice President, Planning & Development, Enbridge from June 2003, and Vice President, Financial Services, of Enbridge from February 2002. Mr. Monaco was Treasurer of the General Partner from February 2002 and Enbridge Management from its formation until his resignation in April 2003.

Stephen J. Neyland was elected Controller of the General Partner and Enbridge Management effective September 2006. Prior to his election he served as Controller, Natural Gas from January 2005, Assistant Controller from May 2004 to January 2005, and in other managerial roles in Finance and Accounting from December 2001 to May 2004. Prior to that time, Mr. Neyland was Controller of Koch Midstream Services from 1999 to 2001.

Kerry C. Puckett was elected Vice President, Engineering and Operations, Gathering and Processing of the General Partner and Enbridge Management in October 2007. Prior to his election he served as General Manager of Engineering and Operations from 2004 and Manager of Operations from 2002 to 2004. Prior to that time, he served as Manager of Business Development for Sid Richardson Energy Services Company.

Jonathan N. Rose was elected as Treasurer of the General Partner and Enbridge Management in January 2008. He was previously Assistant Treasurer of the General Partner and Enbridge Management from July 2005. Mr. Rose is also a Director, Finance of Enbridge, a position he has held from October 2007, prior to which he was Manager, Finance from 2004. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

Allan M. Schneider was elected Vice President, Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Prior to his election he served as Director of Engineering and Operations for Regulated & Offshore and Director of Engineering Services from January 2005. Prior to that, Mr. Schneider was Vice President of Engineering and Operations for Shell Gas Transmission from December 2000.

Bruce A. Stevenson was elected Corporate Secretary of the General Partner and Enbridge Management 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.

Leon A. Zupan was elected Vice President, Liquids Pipelines Operations of the General Partner and Enbridge Management in July 2004, and holds similar responsibilities with Enbridge. Mr. Zupan previously served as Vice President, Development & Services for Enbridge Pipelines from 2000.

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 on our review of the Section 16(a) filings that have been received by us and inquiries made to our directors and executive officers, we believe that all filings required to be made under Section 16(a) during 2008 and prior years were timely made, except that during 2006, George K. Petty, one of the directors of our General Partner and Enbridge Management inadvertently failed to report the purchase of 683 Class A common units by his aunt. Mr. Petty's aunt opened a brokerage account in her name in March 2006, naming Mr. Petty as her attorney-in-fact and purchased 683 Class A common units. Mr. Petty inadvertently failed to file a Form 4 timely to report her purchase when he was granted a power of attorney over this account. This transaction was reported by Mr. Petty on a Form 4 filed in January 2009. According to the Form 4 filing, while Mr. Petty is deemed to be the beneficial owner of the shares of our Class A common units held in the account, his aunt also has dispositive authority with respect to the Class A common units and other securities held in the account.

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 Chief Executive Officer 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 March 22, 2008.

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

We have 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 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 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 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.

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. None of these members is relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are Jeffrey A. Connelly, Dan A. Westbrook, Martha O. Hesse, and George K. Petty. 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. 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.

Enbridge Management's board of directors has determined that Jeffrey A. Connelly and Martha O. Hesse qualify as "Audit Committee financial experts" as defined in Item 407(d)(ii) of SEC Regulation S-K. Each of the members of the Audit, Finance and Risk Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Ms. Hesse serves on the Audit Committees of the General Partner, AMEC plc., Mutual Trust Financial Group and of Terra Industries, Inc. In compliance with the provisions of the Audit, Finance & Risk Committee Charter, the boards of directors of the General Partner and of Enbridge Management have determined that Ms. Hesse's simultaneous service on such audit committees does not impair her ability to effectively serve on the Audit, Finance & Risk Committee.

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.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. Martha O. Hesse serves 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

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and we do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We obtain managerial, administrative and operational services from our general partner, Enbridge Management and Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

The compensation policies and philosophy of Enbridge govern the types and amounts of compensation granted to each of the Named Executive Officers, or NEOs. The NEOs at December 31, 2008 were as follows: Stephen J.J. Letwin, Managing Director, Terrance L. McGill, President, Stephen J. Wuori, Executive Vice President—Liquids Pipelines, Mark A. Maki, Vice President of Finance, and Al Monaco, Executive Vice President. Since the policies and philosophy are those of Enbridge, we refer you to a discussion of those items as set forth in the Executive Compensation section of the Enbridge "Management Information Circular," or MIC, on the Enbridge website at www.enbridge.com. The Enbridge MIC is produced by Enbridge pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Exchange Act; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our general partner.

The boards of directors of Enbridge Management and our general partner do not have separate compensation committees, nor do they have responsibility for approving the elements of compensation presented in the tables which follow this discussion. The boards of directors of Enbridge Management and our general partner do have responsibility for evaluating and determining the reasonableness of the total amount we are charged for managerial, administrative and operational support, including compensation of the NEOs, provided by Enbridge and its affiliates, including our general partner and Enbridge Management.

All Enbridge employees domiciled in the United States are directly employed by its subsidiary, Enbridge Employee Services, Inc., which we refer to as EES. In connection with our annual budget process, we calculate an average "Budgeted Allocation Rate," which represents an estimated average percentage of expected time that will be spent by each of our NEOs on our business during the succeeding year. Those estimates are revised each year based on historical experience. The average Budgeted Allocation Rate was 85% for 2008 and has been set at approximately 77% for 2009. Salary costs of EES are allocated to us based on the percentage of time spent by EES employees on our behalf compared with the total time of all EES employees. We are allocated a portion of the equity-based compensation expense as determined in accordance with U.S. GAAP. Pension expenses of EES (other than expenses under Enbridge's nonqualified supplemental pension plan for U.S.-domiciled employees, which we refer to as the SPP) are allocated to us based on the proportion that the total headcount of EES employees assigned to us bears to the total headcount of EES. For this purpose, an employee of EES is deemed to be assigned to us if he or she works on assets we own. Pension expenses of EES attributable to the SPP are allocated to us based upon the average Budgeted Allocation Rate. EES allocates to us that portion of its compensation expense for Enbridge's Short Term Incentive Plan, a non-equity performance-based incentive plan, equal to the total salaries of employees who perform work for us multiplied by the average Budgeted Allocation Rate divided by EES' total salary expense.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). Accordingly, none of the compensation paid to our NEOs is subject to limitation. The compensation of our NEOs included in the tables below is established by a committee of the board of directors of Enbridge. We have included in the following tables the full amount of compensation and related benefits provided for the NEOs for 2008, 2007 and 2006, together with the approximate amount of compensation cost allocated to us for the years ended December 31, 2008, 2007 and 2006.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards[1] ($)	Option Awards[2] ($)	Non-Equity Incentive Plan Compen-sation[3] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compen-sation[4] ($)	Total ($)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
Stephen J.J. Letwin[5]	2008	531,346		749,768	692,334	530,000	289,000	93,491	2,885,939	2,176,287
Managing Director	2007	483,750	—	325,947	570,647	450,000	335,000	91,003	2,256,347	1,507,502
(Principal Executive Officer)	2006	457,257	—	139,451	316,259	450,000	208,000	156,165	1,727,132	—
Terrance L. McGill	2008	343,170		199,550	312,806	244,910	140,000	33,228	1,273,664	1,113,428
President	2007	323,631	—	111,869	148,725	241,320	128,000	38,835	992,380	815,977
	2006	290,000	—	80,120	191,599	200,000	103,000	33,225	897,944	758,806
Stephen J. Wuori[6][8]	2008	524,390		711,230	472,872	487,805	472,000	78,017	2,746,314	237,928
Executive Vice	2007	—	—	—	—	—	—	—	—	—
President Liquids Pipelines	2006	—	—	—	—	—	—	—	—	—
Mark A. Maki	2008	268,683		119,782	86,400	185,820	96,000	31,779	788,464	678,751
Vice President, Finance	2007	258,681	—	70,850	67,217	161,170	103,000	31,513	692,431	577,011
(Principal Financial Officer)	2006	212,500	—	52,904	74,014	140,000	71,000	30,842	581,260	480,703
Al Monaco[7][8]	2008	367,417		325,028	223,681	361,163	124,000	55,210	1,456,499	—
Executive Vice	2007	—	—	—	—	—	—	—	—	—
President Major Projects	2006	—	—	—	—	—	—	—	—	—

(1) The compensation expense associated with Performance Stock Units, or PSUs, for each NEO reflected in this column represents one-third of the grant date market value for each year the PSUs are outstanding and is measured based on the number of respective units granted, the percentage vested (33%) for each year, the actual or forecast performance multiplier and the market value. For example 2008 includes one-third of the grant date market values for PSUs issued in 2008, 2007 and 2006. In 2008, the compensation expense recorded for PSUs granted in 2008, 2007 and 2006 include performance multipliers for the respective years, which are estimated for 2008 and 2007 and actual for 2006 based upon the expected or achieved levels of performance in relation to established targets for each year. For years prior to the year a payout is made, a performance multiplier of 1.0 is assumed unless the actual multiplier has been determined. Refer also to footnote 2 of the "Grants of Plan-Based Awards" table for additional discussion regarding the PSUs.

The market value for each PSU grant represents the weighted average closing price of an Enbridge Share as quoted on the New York Stock Exchange, or NYSE, for the U.S. dollar (USD) denominated PSUs and the Toronto Stock Exchange, or TSX, for Canadian dollar (CAD) denominated PSUs for the 20 consecutive days prior to the end of the performance period. This same approach was followed for the PSU grant in 2007. However, for 2004 and 2005 PSU grants that were paid in 2006 and 2007, the actual unit price determined for the vested units was applied to determine the market value for the year the PSUs were paid. PSUs granted for 2008 and 2007 were denominated in both USD and CAD, while those granted in 2006 were denominated only in CAD. The PSU expense in CAD is converted to USD based on the average exchange rate for the 20 trading days prior to the measurement date. The PSUs were granted on January 1, 2008, 2007 and 2006, respectively. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

	2008	2007	2006	2005	2004
End of Period Market Value USD	$ 31.40	$ 38.94	$ 34.73	N/A	N/A
End of Period Market Value CAD	$ 38.71	$ 38.77	$ 38.65	$ 39.17	$ 37.10
20-day average exchange rate	$1.2343	$1.0030	$1.1524	$1.1610	$1.2208
Exchange rate on payout date	N/A	N/A	$1.2241	$1.0120	$1.1653
Performance multiplier	1.93	1.45	2.00	0.71	0.28
Assumed performance multiplier	1.00	1.00	N/A	N/A	N/A

(2) The annual expenses for option awards that are granted under the Enbridge Incentive Stock Option Plan (2002) ("ISOP") and the Performance Stock Option Plan (2007) ("PSOP") are determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model for ISOPs and the Bloomberg barrier option valuation model for PSOPs with the following assumptions for the indicated year:

	ISOP			PSOP		
Assumption	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
Expected option term in years	6	6	8	8	8	N/A
Expected volatility	19.90%	18.10%	19.00%	13.60%	13.60%	N/A
Expected dividend yield	3.08%	3.22%	3.23%	3.32%	3.57%	N/A
Risk-free interest rate	3.41%	4.11%	4.16%	3.75%	4.38%	N/A

The fair value of options granted as computed using the above assumptions is expensed over the shorter of the vesting period for the options and the period to early retirement eligibility. The exercise price and fair value information for all option grants has been converted to USD using the exchange rates as set forth in the tables below. The fair values of all grants on the grant date have been converted to USD using the average exchange rates, representing the exchange rate for the period during which the expense was recognized.

	ISOP			PSOP		
	2008	2007	2006	2008	2007	2006
Exercise price in CAD	$ 40.42	$ 38.26	$ 36.47	$ 40.42	$ 36.57	N/A
Exercise price in USD	$ 40.33	$ 32.59	$ 31.58	$ 39.79	$ 34.03	N/A
Grant date exchange rate for $1 USD	$1.0160	$1.1740	$1.1548	$1.0160	$1.0746	N/A

	ISOP			PSOP		
	2008	2007	2006	2008	2007	2006
Vesting period term in years	4	4	4	5	5	N/A
Option fair value on grant date in CAD	$ 6.20	$ 6.16	$ 6.28	$ 4.82	$ 3.40	N/A
Option fair value on grant date in USD	$ 5.82	$ 5.25	$ 5.54	$ 4.74	$ 3.16	N/A
Average exchange rate for $1 USD	$1.0660	$1.0748	$1.1341	$1.0660	$1.0748	N/A

(3) Non-equity incentive plan compensation represents awards that are paid in February for amounts that are earned in the immediately preceding fiscal year under the Enbridge Short Term Incentive Plan, or STIP. The Enbridge STIP is a performance-based plan where measurement metrics are established at the beginning of each fiscal year that promotes the achievement of financial, safety, corporate governances, and individual goals.

(4) The table which follows labeled “All Other Compensation” sets forth the elements comprising the amounts presented in this column.

(5) Mr. Letwin relocated to the United States on May 1, 2006, and became Managing Director of our general partner and Enbridge Management. Mr. Letwin is also an executive officer of Enbridge with responsibility for other Enbridge operations in addition to those of our general partner, Enbridge Management, and us that he assumed in May 2006. We have included the full amount of Mr. Letwin’s compensation in the summary compensation table. However, we were not charged the cost of Mr. Letwin’s compensation for the period from January 1, 2006 through December 31, 2006, since the allocation to us of compensation to Mr. Letwin was not contemplated in our budget. As a result, Mr. Letwin’s compensation was borne by other Enbridge affiliates.

For the year ended December 31, 2006, we used a weighted average exchange rate of $1.1519 CAD = $1 USD to convert the compensation costs to USD for Mr. Letwin, which represents the weighted average exchange rate for the period from May 1, 2006 through December 31, 2006. The costs associated with the PSUs and options Mr. Letwin was granted were borne by Enbridge and other affiliates where he is also an officer because the grant occurred prior to his becoming a managing director of our general partner and Enbridge Management.

(6) Mr. Wuori is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for our general partner and Enbridge Management. Mr. Wuori is compensated by affiliates of Enbridge in CAD which we have converted to USD using the weighted average exchange rates for the years ended December 31, 2008 as of $ 1.0660 CAD = $1 USD. The costs associated with the PSUs and options Mr. Wuori was granted in 2008 were borne by Enbridge and other affiliates where he is also an officer. We are allocated a portion of the remaining elements of Mr. Wuori’s compensation based on the approximate percentage of time he devotes to us and Enbridge Management.

(7) Mr. Monaco is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for our general partner and Enbridge Management. Mr. Monaco is compensated by affiliates of Enbridge in CAD which we have converted to USD using the weighted average exchange rates for the year ended December 31, 2008 as of $1.0660 CAD = $1 USD. The costs associated with the PSUs and options Mr. Monaco was granted in 2008 were borne by Enbridge and other affiliates where he is also an officer.

(8) Messrs. Wuori and Monaco were elected officers of Enbridge Management and our general partner in January 2008, prior to which they held other responsibilities with Enbridge.

ALL OTHER COMPENSATION
(For the years ended December 31, 2008, 2007 and 2006)

Name	Year	Flexible Benefits[2] $	401(k) Matching Contributions[3] $	Relocation Allowance $	Mortgage Interest Payments $	Other Benefits[4] $	Total $
Stephen J.J. Letwin	2008	35,000	11,500	—	43,371	3,620	93,491
	2007	35,000	11,250	—	40,321	4,432	91,003
	2006	35,169	11,000	77,500	25,701	6,795	156,165
Terrance L. McGill	2008	20,000	11,500	—	—	1,728	33,228
	2007	20,000	11,250	—	—	7,585	38,835
	2006	20,000	11,000	—	—	2,225	33,225
Stephen J. Wuori[1]	2008	66,694	—	—	—	11,323	78,017
Mark A. Maki	2008	20,000	11,500	—	—	279	31,779
	2007	20,000	11,250	—	—	263	31,513
	2006	20,000	10,625	—	—	217	30,842
Al Monaco[1]	2008	49,997	—	—	—	5,213	55,210

(1) The amounts reported in this table for Mr. Wuori and Mr. Monaco, our NEOs domiciled in Canada, have been converted from CAD to USD using the average exchange rate for 2008 of $1.0660 CAD = $1 USD.

(2) Flexible benefits for our U.S. domiciled NEOs represent a perquisite allowance that is paid in cash as additional compensation. Our NEOs domiciled in Canada receive flexible benefits based on their family status and base salary. For our NEOs that are domiciled in Canada, the flexible benefits can be used to purchase additional benefits, paid in cash, or be applied as contributions to the Enbridge Stock Purchase and Savings Plan; or (b) paid as additional compensation.

(3) Our NEOs that are domiciled in the United States and participate in the Enbridge Employee Services, Inc. Savings Plan (the "401(k) Plan") may contribute up to 50 percent of their base salary which is matched up to 5 percent by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge shares at market value and employee contributions may be used to purchase Enbridge shares or 22 designated funds.

(4) Other benefits include professional financial services, term life insurance premiums, parking, and home security and internet services.

We do not maintain any compensation plans for the benefit of the NEOs under which equity interests in Enbridge Management or the Partnership may be awarded. However, Enbridge allocates to us the compensation expense it recognizes under FAS 123(R) in connection with recording the fair value of its restricted stock units and outstanding stock options granted to certain of our officers, including the NEOs. The costs we are charged with respect to option grants represent a portion of the costs determined in accordance with U.S. GAAP.

The performance stock units are granted to the NEOs pursuant to the Enbridge Inc. Performance Stock Unit Plan and stock options are granted pursuant to the Enbridge Incentive Stock Option Plan (2002) and the Performance Stock Option Plan (2007). Awards under these plans provide long-term incentive and are administered by the Human Resources & Compensation Committee of Enbridge. The performance stock units granted from 2004 through 2006 and stock option grants are denominated in CAD. The performance stock units granted in 2007 and 2008 to our U.S.-domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in Canadian dollars. The following two tables set forth information concerning performance stock units and stock options outstanding at December 31, 2008, and the number of awards vested and exercised during the years ended December 31, 2007 and 2006, by each of the NEOs:

GRANTS OF PLAN-BASED AWARDS

Name (a)	Plan Name[1] (b)	Approval Date (b)	Grant Date (b)	Estimated Future Payouts under non-Equity Incentive Plan Awards[5] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Option Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options[3][4] (#) (j)	Exercise or Base Price of Option Awards[3][4] ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards[2][3][4] ($) (l)
Stephen J.J. Letwin	PSUP	5-Feb-08	1-Jan-08	—	—	—	5,625	9,000	18,000	—	—	—	350,460
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	60,000	40.33	349,200
	STIP	12-Feb-09	27-Feb-09	—	265,000	530,000	—	—	—	—	—	—	—
Terrance L. McGill	PSUP	5-Feb-08	1-Jan-08	—	—	—	2,000	3,200	6,400	—	—	—	124,608
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	49,500	40.33	288,090
	STIP	3-Feb-09	27-Feb-09	—	134,080	268,160	—	—	—	—	—	—	—
Stephen J. Wuori	PSUP	5-Feb-08	1-Jan-08	—	—	—	5,625	9,000	18,000	—	—	—	349,977
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	60,000	39.79	366,160
	STIP	12-Feb-09	27-Feb-09	—	265,947	531,895	—	—	—	—	—	—	—
Mark A. Maki	PSUP	5-Feb-08	1-Jan-08	—	—	—	1,188	1,900	3,800	—	—	—	73,986
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	30,100	40.33	175,182
	STIP	3-Feb-09	27-Feb-09	—	92,860	185,720	—	—	—	—	—	—	—
Al Monaco	PSUP	5-Feb-08	1-Jan-08	—	—	—	4,375	7,000	14,000	—	—	—	272,204
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	45,000	39.79	274,620
	PSOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	250,000	39.79	1,185,000
	STIP	12-Feb-09	27-Feb-09	—	187,617	375,235	—	—	—	—	—	—	—

(1) The abbreviated plan names are defined as follows:

a. PSUP refers to the Enbridge Performance Stock Unit Plan (2007), an equity- based incentive plan.

b. ISOP refers to the Enbridge Incentive Stock Option Plan (2007), a qualified stock option plan.

c. PSOP refers to the Enbridge Performance Stock Option Plan (2007), a performance-based, incentive stock option plan.

d. STIP refers to the Enbridge Short Term Incentive Plan (2006), a non-equity performance-based incentive plan.

(2) Our NEOs are eligible to receive annual grants of Performance Stock Units, or PSUs, under the Performance Stock Unit Plan, or PSUP, an equity-based, long-term incentive plan, administered by a committee of the board of directors of Enbridge. The initial value of each of these PSUs on the grant date is equivalent to the weighted average closing price of one Enbridge share as quoted on the Toronto Stock Exchange or New York Stock Exchange for the 20 trading days immediately preceding the start of the performance period. The initial PSUs granted are increased for quarterly dividends paid during the three-year period on an Enbridge share. Awards under the 2008 PSUP are paid out in cash at the end of a three-year performance cycle based on: (1) an earnings per share, or EPS target for Enbridge based on the long range plan of the organization and (2) the price to earnings ratio of an Enbridge share relative to a defined group of peer organizations established in advance by a committee of the board of Enbridge. The performance measures for grants awarded from 2004 through 2006 are based on (1) the market value of an Enbridge share at the end of the three-year period; and (2) the total shareholder return for Enbridge over a three-year period in relation to a peer group of companies established in advance by a committee of the board of directors of Enbridge. Payments under the PSUP may be increased up to 200 percent of the original award when Enbridge outperforms its peer group. If Enbridge fails to meet threshold performance levels, no payments are made under the PSUP. Dividends are paid on the PSUs which are invested in additional PSUs at the then current market price for one share of Enbridge common stock, which are not included in the estimated future payout amounts, but have been included in the compensation associated with stock awards in the Summary Compensation table. Enbridge does not issue any shares in connection with the PSUP.

The threshold at which PSUs are issued represents 62.5 percent of the number of PSUs initially granted and is the lowest level at which PSUs will be issued based on the performance criteria discussed above. The target level at which PSUs are issued represents 100 percent of the number of PSUs initially granted and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200 percent of the number of PSUs initially granted and may occur when Enbridge exceeds the established performance criteria.

PSUs vest at the end of a three year performance period that begins on January 1 of the year granted and during the term the PSUs are outstanding, a liability and expense are recorded by Enbridge based on the number of PSUs outstanding and the current market price of an Enbridge share and beginning in 2008 at each measurement date a forecast performance multiplier is applied to the PSUs outstanding based on the expected levels of performance in relation to the established targets for each year. The grant date fair value for each PSU granted to each of our U.S. based NEOs was $38.94 USD, representing the weighted average closing price of one Enbridge share as quoted on the New York Stock Exchange for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2008. The grant date fair value for each PSU granted to each of our Canadian based NEOs was $38.77 CAD, representing the weighted average closing price of one Enbridge share as quoted on the Toronto Stock Exchange for the 20 days immediately preceding the start of the performance period that began on January 1, 2008. We have converted the grant date fair value for the Canadian PSU grants made from CAD to USD using an exchange rate of $1.003 CAD = $1 USD, representing the weighted average noon rate for 20 trading days immediately preceding the performance period that began on January 1, 2008.

(3) The Enbridge Incentive Stock Option Plan (2007) is administered by a committee of the Enbridge board of directors and if an option is granted during a trading blackout period, the exercise price of an option grant is determined as the weighted average trading price of an Enbridge share on the Toronto Stock Exchange or New York Stock Exchange for the five trading days immediately prior to the effective date of the option. In the event an option grant is granted during a period a trading blackout is not in effect, the exercise price of the option grant is equal to the last reported sales price on the Toronto Stock Exchange or New York Stock Exchange for the day immediately preceding the grant date. During 2008, each of the NEOs received grants of Enbridge incentive stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the incentive stock options at the time of grant was $40.42 CAD for Canadian domiciled NEOs and $40.33 USD for NEOs domiciled in the United States.

The amounts included as the grant date fair value for the 2008 incentive stock option awards represent the amount determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Sholes option pricing model with the following assumptions:

USD Option Value	CAD Option Value
6 years expected term;	6 years expected term;
19.9% expected volatility;	18.1% expected volatility;
3.41% expected dividend yield; and	3.32% expected dividend yield; and
3.081% risk free interest rate.	3.612% risk free interest rate.

The fair value of options granted as computed using these assumptions is $5.82 USD or $6.20 CAD. The $6.20 CAD option value and the $40.42 CAD exercise price have been converted to USD using an exchange rate of $1.0160 CAD = $1 USD representing the noon buying rate in New York for transfers of CAD on the grant date of February 19, 2008. The grant date fair value is expensed over the shorter of the vesting period for the options, generally 4 years, and the period to early retirement eligibility. Mr. Letwin and Mr. McGill are both within three years of early retirement eligibility and as a result the grant date fair value of options they are awarded is expensed in the year granted.

(4) The Enbridge Performance Stock Option Plan (2007) is administered by a committee of the Enbridge board of directors and if a performance option is issued during a trading blackout period, the exercise price of a performance option grant is determined as the weighted average trading price of an Enbridge share on the Toronto Stock Exchange or New York Stock Exchange for the five trading days immediately prior to the effective date of the performance option. In the event an option grant is issued during a period a trading blackout is not in effect, the exercise price of the performance option grant is equal to the last reported sales price on the Toronto Stock Exchange or New York Stock Exchange for the day immediately preceding the grant date. Performance-based stock options, or PBSOs, are similar to the incentive stock options, except that the quantities become exercisable subject to both the achievement of specified share price targets and time requirements.

One half of the PBSOs become exercisable if the first share price hurdle is achieved and 100% of the grant becomes exercisable if the second share price hurdle is achieved within a 6 1/2 year time period. The term of each grant is 8 years provided the performance criteria are met. PBSOs are granted on an infrequent basis and provided the eligible NEO the opportunity to acquire one Enbridge share for each option held when the specified term and share price targets are met. During 2008, Mr. Monaco received grants of Enbridge performance stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the PBSOs at the time of grant was $40.42 CAD which has been converted into USD using an exchange rate of $1.0160 CAD = $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of February 19, 2008.

The amounts included as the grant date fair value for the 2008 PBSO awards represent the amount determined by computing the fair value of the options under FAS 123(R) on the grant date using the Bloomberg barrier option valuation model with the following assumptions:

- 8 years expected term;
- 13.6% expected volatility;
- 3.32% expected dividend yield; and
- 3.75% risk free interest rate.

The fair value of options granted as computed using these assumptions is $4.82 CAD which has been converted to USD using an exchange rate of $1.0160 CAD = $1 USD which equates to a grant date fair value of $ 4.74 USD per option granted. The grant date fair value is expensed over the shorter of the vesting period for the options (generally 5 years) and the period to early retirement eligibility.

(5) The estimated future payouts under the Enbridge STIP are determined for the indicated fiscal year, based upon achievement of performance goals established at the beginning of the fiscal year for each of the NEOs. The payouts earned under the STIP for each fiscal year are generally paid to the NEO on the last business day of February of the year following the fiscal year in which the payout is earned. The performance goals include pre-determined financial, safety, corporate governance and operational goals that are aligned with the business objectives for Enbridge and the business unit(s) to which the NEOs are assigned, in addition to individual performance objectives. Based upon the level achieved in meeting the pre-determined objectives, a multiple is determined that can vary from a low of zero, if the level of achievement is significantly below the stated objectives, to a high of two, if the level of achievement significantly exceeds the stated objective, with the mid-point or target representing achievement of 100 percent of the pre-established goals. The multiple is then applied to the bonus level, represented as a percentage of base salary, for each NEO. The estimated future payouts under non-equity incentive plan awards for Mr. Wuori and Mr. Monaco have been converted to USD using the average exchange rate for 2008 of $1.0660 CAD = $1 USD. The STIP targets for each NEO expressed as a percentage of salary for 2008 is as follows:

Name	**Threshold**	**Target**	**Maximum**
Stephen J.J. Letwin	—	50%	100%
Terrance L. McGill	—	40%	80%
Stephen J. Wuori	—	50%	100%
Mark A. Maki	—	35%	70%
Al Monaco	—	50%	100%

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable [(1)(2)] (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date[(1)] (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(3)] (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
Stephen J.J. Letwin	—	60,000	—	40.33	19-Feb-18	—	—	9,295	582,509
	11,250	33,750	—	32.59	9-Feb-17	—	—	9,609	452,417
	26,850	26,850	—	31.58	13-Feb-16				
	—	13,100	—	25.49	3-Feb-15				
	—	330,000	—	34.03	15-Aug-15				
Terrance L. McGill	—	49,500	—	40.33	19-Feb-18	—	—	3,305	207,114
	4,100	12,300	—	32.59	9-Feb-17	—	—	3,417	160,859
	9,450	9,450	—	31.58	13-Feb-16				
	15,300	5,100	—	25.49	3-Feb-15				
	40,000	—	—	19.30	4-Feb-14				
	36,400	—	—	13.69	6-Feb-13				
Stephen J. Wuori	—	60,000	—	39.79	19-Feb-18	—	—	9,292	579,314
	11,250	33,750	—	32.59	9-Feb-17	—	—	9,606	449,955
	24,150	24,150	—	31.58	13-Feb-16				
	34,350	11,450	—	25.49	3-Feb-15				
	—	330,000	—	34.03	15-Aug-15				
	39,000	—	—	19.30	4-Feb-14				
	80,000	—	—	13.69	6-Feb-13				
	80,000	—	—	13.68	5-Feb-12				
	100,000	—	—	14.63	16-Sep-10				
Mark A. Maki	—	30,100	—	40.33	19-Feb-18	—	—	1,962	122,974
	2,875	8,625	—	32.59	9-Feb-17	—	—	2,242	105,564
	5,550	5,550	—	31.58	13-Feb-16				
	8,550	2,850	—	25.49	3-Feb-15				
	30,000	—	—	19.30	4-Feb-14				
	33,400	—	—	13.69	6-Feb-13				
	16,000	—	—	13.68	5-Feb-12				
Al Monaco	—	45,000	—	39.79	19-Feb-18	—	—	7,227	450,577
	3,550	10,650	—	32.59	9-Feb-17	—	—	2,988	139,986
	8,150	8,150	—	31.58	13-Feb-16				
	14,100	4,700	—	25.49	3-Feb-15				
	—	250,000	—	39.79	15-Aug-15				
	27,400	—	—	19.30	4-Feb-14				
	24,000	—	—	13.69	6-Feb-13				
	12,000	—	—	13.68	5-Feb-12				
	12,000	—	—	12.43	21-Feb-11				
	4,000	—	—	9.12	23-Feb-10				
	16,000	—	—	11.81	17-Jun-09				

(1) Each incentive stock option ("ISO") award has a 10 year term and vests prorata as to one fourth of the option award beginning on the first anniversary of the grant date; thus the vesting dates for each of the option awards in this table can be calculated accordingly. As an example, for Mr. Letwin's grant that expires on February 19, 2018, the grant date would be ten years prior or February 19, 2008 and as a result, the remaining unexercisable amounts become fully vested on February 19, 2012 representing 4 years following the grant date.

(2) Performance-based stock options, or PBSOs, were provided to certain of our NEOs on September 16, 2002, August 15, 2007 and February 19, 2008 are similar to the incentive stock options, except that the quantity that become exercisable are subject to both time and performance requirements. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge share for each option held when the specified time and performance conditions are met. The PBSOs granted September 16, 2002, became exercisable, as to 50 percent of the grant, when the price of an Enbridge Share exceeded $30.50 for 20 consecutive days during the period September 16, 2002 to September 16, 2007, and became exercisable as to 100 percent when the price of an Enbridge share exceeded $35.50 for 20 consecutive days during the same period. As a result of achieving the established performance criteria, the initial five year term of the options was extended to 8 years expiring on September 16, 2010. In addition to the performance hurdles, the PBSOs are also time vested 20% annually over 5 years. As of December 31, 2007, 100 percent of the PBSOs granted September 16, 2002, had vested and were exercisable and none the of the PBSOs granted August 15, 2007 and February 19, 2008 were vested or exercisable.

(3) The unearned shares, units or other rights that have not vested under stock awards represent PSUs for which the performance criteria discussed in footnote number 2 of the Grants of Plan-Based Awards table have not been achieved. The PSUs become vested upon achieving the established performance criteria. The amounts represented in the column are the number of units that have not vested at the closing share price of one Enbridge share on the New York Stock Exchange at $32.47 per share or the Toronto Stock Exchange at $39.56 per share converted to USD of $32.30 per share at the conversion rate of $1.2246 CAD = $1 USD. The values presented assume a performance multiplier of 1.93 for PSUs granted in 2008 and 1.45 for PSUs granted in 2007, which amounts are determined based on forecasts of performance at December 31, 2008.

(4) The exercise prices of the ISOs and PBSOs issued during 2006 and prior years are denominated in CAD. Beginning in 2007, ISOs and PBSOs granted to NEOs domiciled in the United States are denominated in USD while those NEOs domiciled in Canada are denominated in CAD. The ISOs and PBSOs denominated in CAD have been converted to USD using the exchange rate on the grant dates as set forth below:

Issuance Date	Option Exercise Price CAD	Exchange Rate USD/CAD	Option Exercise Price USD
June 17, 1999	$17.2500	$0.6845	$11.8076
February 23, 2000	13.3500	0.6829	9.1167
February 21, 2001	19.1000	0.6508	12.4303
February 5, 2002	21.8500	0.6259	13.6759
September 16, 2002	23.1500	0.6319	14.6285
February 6, 2003	20.8250	0.6572	13.6862
February 4, 2004	25.7200	0.7504	19.3003
February 3, 2005	31.6800	0.8046	25.4897
February 13, 2006	36.4700	0.8660	31.5830
February 9, 2007	38.2600	0.8519	32.5937
August 15, 2007	36.5700	0.9306	34.0320
February 19, 2008	40.4200	0.9843	39.7854

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting(1) (#)	Value Realized on Vesting(2) ($)
Stephen J.J. Letwin	50,300	708,811	10,243	646,813
Terrance L. McGill	10,000	241,810	3,635	229,514
Stephen J. Wuori	180,000	3,630,954	9,252	584,218
Mark A. Maki	7,500	165,760	2,093	132,145
Al Monaco	4,600	133,706	3,304	208,649

(1) The number of shares acquired on vesting for stock awards represents the number of PSUs issued in 2006 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2008. As discussed in footnote number 2 of the Grants of Plan-Based Awards table, no shares are issued with respect to the PSUs that become vested; rather, cash is paid in an amount based on the value of an Enbridge share at the maturity date and the level of achievement of the established performance goals.

(2) The value realized on vesting is determined based on the final value of an Enbridge share of $38.65 CAD multiplied by a 2.0 performance factor multiplied by the number of PSUs, which is then converted to USD using an exchange rate of $1.2241 CAD = $1 USD for the PSUs that matured on December 31, 2008.

The value realized on the exercise of options by Mr. Letwin has been converted to USD using an exchange rate of $1.0065 CAD = $1USD for 11,000 options exercised on March 4, 2008 and an exchange rate of $1.0107 CAD = $1USD for 39,300 options exercised on May 26, 2008.

The value realized on the exercise of options by Mr. McGill has been converted to USD using an exchange rate of $1.0065 CAD = $1USD for 10,000 options exercised on March 4, 2008.

The value realized on the exercise of options by Mr. Wuori has been converted to USD using an exchange rate of $1.0255 CAD = $1USD for 80,000 options exercised on February 28, 2008 and an exchange rate of $0.9957 CAD = $1USD for 100,000 options exercised on April 3, 2008.

The value realized on the exercise of options by Mr. Maki has been converted to USD using an exchange rate of $1.0201 CAD = $1USD for 6,500 options exercised on February 27, 2008 and $1.0255 CAD = $1USD for 1,000 options exercised on February 28, 2008.

The value realized on the exercise of options by Mr. Monaco has been converted to USD using an exchange rate of $1.0172 CAD = $1USD for 4,600 options exercised on May 21, 2008.

Pension Plan

Enbridge sponsors two basic pension plans, the Retirement Plan for Employees' Annuity Plan ("EI RPP") and the Enbridge Employee Services, Inc. Employees' Annuity Plan ("QPP"), which provide defined pension benefits and cover employees in Canada and the United States, respectively. Both plans are non-contributory. Enbridge also sponsors supplemental nonqualified retirement plans in both Canada ("EI SPP") and the United States ("US SPP"), which provide pension benefits for the NEOs in excess of the tax-qualified plans' limits. We collectively refer to the EI RPP, the QPP, the EI SPP and the US SPP as the "Pension Plans." Retirement benefits under the Pension Plans are based on the employees' years of service and final average remuneration with an offset for Social Security benefits. These benefits are partially indexed to inflation after a named executive officer's retirement.

For service prior to January 1, 2000, the Pension Plans provide 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. For Mr. Wuori, the average salary also includes the highest three pensionable bonuses out of the last five years of continuous service, represented by the greater of 50% of the actual bonus paid or the lesser of the actual or target bonuses. 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 three years prior to January 1, 2000, Mr. Monaco elected to participate in the defined contribution option of the EI RPP. Mr. Monaco will receive a benefit at retirement associated with his participation in the defined contribution option of the EI RPP equal to the amounts contributed on his behalf and the earnings attributed to such amounts.

For service after December 31, 1999, the Pension Plans provide for senior management employees, including the NEOs, 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 service, 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.

The table below illustrates the total annual pension entitlements at December 31, 2008 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pensions payable in CAD into USD at the rate of $1.0704 CAD = $1.00 USD an approximate average of the exchange rate during 2008. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	6.00% at year end 2008
Salaries	Current
Inflation	2.50% per year
Retirement age	Age when first eligible for an unreduced pension(1)
Terminations	None
Mortality	
Pre-retirement	None
Post-retirement	PPA generational annuitant and nonannuitant tables (RP 2000 projected to 2005 at year end 2007)

(1) This is age 60 for all executives except for Mr. Wuori and Mr. Maki, who are eligible for an unreduced pension at age 55.

Plan benefits that exceed maximum pension rules applicable to registered plan benefits are paid from the Enbridge supplemental pension plans. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

Mr. Letwin was granted six additional years of credited service on his employment date based on the pension formula applicable for service prior to January 1, 2000.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Stephen J.J. Letwin	EI RPP	7.08	183,000	—
	EI SPP	13.08	1,576,000	—
	QPP	2.67	107,000	—
	USSPP	2.67	285,000	—
Terrance L. McGill	US QPP	6.50	105,000	—
	US SPP	6.83	514,000	—
Stephen J. Wuori	EI RPP	14.67	473,000	—
	EI RPP	14.67	2,049,000	—
	US QPP	13.83	690,000	—
Mark A. Maki	EI RPP	1.92	42,000	—
	EI SPP	1.92	55,000	—
	US QPP	20.40	686,000	—
	US SPP	20.40	168,000	—
Al Monaco	EI RPP(1)	13.08	230,000	—
	EI SPP	10.08	428,000	—

(1) EI RPP Service includes three years spent in defined contribution component of the Pension Plan. The current defined contribution balance has been included in the EI RPP accumulated benefit.

Employment and Severance Agreements

Enbridge has entered into an executive employment agreement with each of Stephen J.J. Letwin, Managing Director and Chief Executive Officer of Enbridge Management and our general partner, and Stephen J. Wuori, Executive Vice President—Liquids Pipelines of Enbridge Management and our general partner. Each of the agreements was entered into effective April 14, 2003 and was amended effective June 24, 2004. The term of each of the agreements continues until the earlier of: the applicable executive officer's voluntary retirement in accordance with Enbridge's retirement policies for its senior employees, voluntary resignation, death or termination of employment by Enbridge of the applicable executive officer.

Each of the agreements provides that Enbridge will pay severance benefits to each of Mr. Letwin and Mr. Wuori if such executive officer's employment is terminated (1) involuntarily without cause or because of the disability of such executive officer; (2) on the election of such executive officer within 90-days following a constructive termination; (3) on the election of such executive officer within 90 days following the one-year anniversary of a change in control of Enbridge, other than certain types of changes of control initiated by management or the board or directors of Enbridge; and (4) by Enbridge within one-year of certain types of changes of control of Enbridge, which change of control is initiated by management or the board of directors of Enbridge. On the occurrence of one of the foregoing events, Enbridge will pay to the applicable executive officer:

- an amount equal to two times the (1) annual salary of such executive officer and (2) the average of the last two payments to such executive officer under STIP;
- an amount equal to two times the cash value of the last annual flex credit allowance provided to such executive officer under Enbridge's flexible benefit program, unless such executive officer continues to be covered under Enbridge's annuitant benefit program or becomes covered under the benefits program of another employer;
- an amount equal to the value of such executive officer's annual incentive bonus to be paid for the calendar year in which termination occurs, pro rated based on the number of days of such executive officer's employment in such year;

- an amount in cash equal to the value of all of such executive officer's accrued and unpaid vacation pay;
- an amount in cash equal to two times the value of the last annual flexible perquisite allowance provided to such executive officer under Enbridge's flexible perquisites program, less any amounts paid to such executive officer but unearned; and
- up to a maximum of $10,000 for financial or career counseling assistance.

In addition, the executive officer will receive:

- two additional years of service under Enbridge's defined benefit pension plan and supplemental benefit pension plan; and
- the right to exercise all exercisable and unexercised options and an amount equal to the excess, if any, of the fair market value of the shares underlying unexercised and un-exercisable options over the exercise price for such options.

For purposes of each of the employment agreements of Mr. Letwin and Mr. Wuori, a "change of control" means:

- the sale to a person or acquisition by a person not affiliated with Enbridge or its subsidiaries of net assets of Enbridge or its subsidiaries having a value greater than 50% of the fair market value of the net assets of Enbridge and its subsidiaries determined on a consolidated basis prior to such sale whether such sale or acquisition occurs by way of reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise;
- any change in the holding, direct or indirect, of shares of Enbridge by a person not affiliated with Enbridge as a result of which such person, or a group of persons, or persons acting in concert, or persons associated or affiliated with any such person or group within the meaning of the Securities Act (Alberta), are in a position to exercise effective control of Enbridge whether such change in the holding of such shares occurs by way of takeover bid, reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise; and for the purposes of this Agreement, a person or group of persons holding shares or other securities in excess of the number which, directly or following conversion thereof, would entitle the holders thereof to cast 20% or more of the votes attaching to all shares of Enbridge which, directly or following conversion of the convertible securities forming part of the holdings of the person or group of persons noted above, may be cast to elect directors of Enbridge shall be deemed, other than a person holding such shares or other securities in the ordinary course of business as an investment manager who is not using such holding to exercise effective control, to be in a position to exercise effective control of Enbridge;
- any reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction involving Enbridge where shareholders of Enbridge immediately prior to such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction hold less than 60% of the shares of Enbridge or of the continuing corporation following completion of such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, transfer, sale or other transaction;
- Enbridge ceases to be a distributing corporation as that term is defined in the Canada Business Corporations Act;
- any event or transaction which Enbridge board of directors, in its discretion, deems to be a change of control; or
- the Enbridge board of directors no longer comprises a majority of incumbent directors, who are defined as directors who were directors immediately prior to the occurrence of the transaction, elections or appointments giving rise to a change of control and any successor to an incumbent director who was recommended for election at a meeting of Enbridge shareholders, or elected or appointed to succeed any incumbent director, by the affirmative vote of the directors, which affirmative vote includes a majority of the incumbent directors then on the board of directors.

Each of Mr. Letwin and Mr. Wuori is subject during his employment (and for two years thereafter with regard to disclosure of confidential information) to restrictions on (1) any practice or business in competition with Enbridge or its affiliates and (2) disclosure of the confidential information of Enbridge or its affiliates.

In the event of a termination that would result in severance benefits to either Mr. Letwin or Mr. Wuori, Enbridge would owe incremental benefits with a value of approximately $5 million to each. Such amounts assume that termination was effective as of December 31, 2008, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to each of Mr. Letwin and Mr. Wuori upon termination under such circumstances. The actual amounts to be paid out can only be determined at the time of such executive's separation from Enbridge.

Director Compensation

As a partnership, we are managed by Enbridge Management, as the delegate of Enbridge Energy Company, Inc., our general partner. The boards of directors of Enbridge Management and our general partner, which are comprised of the same persons, perform for us the functions of a board of directors of a business corporation. We are allocated 100 percent of the director compensation of these board members. Enbridge employees who are members of the boards of directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities.

Under the Director Compensation Plan, directors receive an annual retainer of $75,000 and no additional fees for attending regular meetings. Effective July 1, 2008, the annual retainer paid to the Chairman of the Board was increased to $15,000 and the annual retainer paid to the Chairman of the Audit Committee was increased to $10,000. The out of state travel fee is $1,500 per meeting. The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in either or both of us or Enbridge Management, of at least two times the annual board retainer, which currently would be $150,000 (i.e., 2 X $75,000 = $150,000). Directors would be expected to achieve the foregoing level of equity ownership by the later of January 1, 2011 or five years from the date he or she became a director. In addition, on January 30, 2009 the Director Compensation Plan was amended to increase the retainer paid to a Director serving as Chairman of any Special Committee that may be constituted from time to time to $5,000 for each assignment and that each member of the Special Committee should receive $1,500 per meeting.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Jeffrey A. Connelly *Audit Committee Chairman*	91,250	—	—	—	—	—	91,250
Martha O. Hesse *Chairman of the Board*	101,000	—	—	—	—	—	101,000
George K. Petty	85,500	—	—	—	—	—	85,500
Dan A. Westbrook	90,000	—	—	—	—	—	90,000

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.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Enbridge Energy Management, L.L.C., as delegate of the general partner of Enbridge Energy Partners, L.P., has reviewed and discussed the Compensation Discussion and Analysis section of this report with management and, based on that review and discussion, has recommended that the Compensation Discussion and Analysis be included in this report.

/s/ STEPHEN J.J. LETWIN

Stephen J.J. Letwin
Managing Director and Director

/s/ TERRANCE L. MCGILL

Terrance L. McGill
President and Director

/s/ STEPHEN J. WUORI

Stephen J. Wuori
Executive Vice President—Liquids Pipelines and Director

/s/ JEFFREY A. CONNELLY

Jeffrey A. Connelly
Director

/s/ MARTHA O. HESSE

Martha O. Hesse
Director

/s/ GEORGE K. PETTY

George K. Petty
Director

/s/ DAN A. WESTBROOK

Dan A. Westbrook
Director

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 18, 2009, with respect to persons known to us to be the beneficial owners of more than 5% of any 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	15,247,549	100.0
Enbridge Energy Company, Inc. 1100 Louisiana, Suite 3300 Houston, TX 77002	Class A common units	16,250,000	21.4
	Class B common units	3,912,750	100.0
	Class C units	6,653,893	32.8
CDP Infrastructures Fund G.P. 1000 place Jean-Paul-Riopelle Montreal, Québec H2Z 2B3	Class C units	12,214,001	60.1
Tortoise Energy Infrastructure Corporation 10801 Mastein Blvd., Suite 222 Overland Park, KS 66210	Class C units	1,112,021	5.5

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 18, 2009, with respect to each class of our units and the Listed Shares of Enbridge Management beneficially owned by the NEOs, directors and nominees for director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

	Enbridge Energy Partners, L.P.			Enbridge Energy Management, L.L.C.		
Name	Title of Class	Amount and Nature of Beneficial Ownership(1)	Percent Of Class	Title of Class	Number of Shares(1)	Percent Of Class
Martha O. Hesse	Class A common units	—	—	Listed Shares	23,772	*
Jeffrey A. Connelly	Class A common units	7,000	*	Listed Shares	—	—
George K. Petty(2)	Class A common units	3,300	*	Listed Shares	2,937	*
Dan A. Westbrook(3)	Class A common units	9,500	*	Listed Shares	—	—
Stephen J.J. Letwin(4)	Class A common units	22,000	*	Listed Shares	—	—
Terrance L. McGill	Class A common units	2,000	*	Listed Shares	1,587	*
Stephen J. Wuori	Class A common units	—	—	Listed Shares	—	—
Richard L. Adams	Class A common units	—	—	Listed Shares	—	—
E. Chris Kaitson	Class A common units	—	—	Listed Shares	—	—
Douglas V. Krenz	Class A common units	—	—	Listed Shares	—	—
John A. Loiacono	Class A common units	1,000	*	Listed Shares	—	—
Mark A. Maki	Class A common units	—	—	Listed Shares	—	—
Al Monaco	Class A common units	—	—	Listed Shares	—	—
Stephen J. Neyland	Class A common units	—	—	Listed Shares	—	—
Kerry C. Puckett	Class A common units	1,000	*	Listed Shares	—	—
Jonathan N. Rose	Class A common units	—	—	Listed Shares	—	—
Allan M. Schneider	Class A common units	—	—	Listed Shares	—	—
Bruce A. Stevenson	Class A common units	—	—	Listed Shares	—	—
Leon A. Zupan	Class A common units	—	—	Listed Shares	—	—
All Officers, directors and nominees as a group (19 persons)	Class A common units	45,800	*	Listed Shares	28,296	*

* Less than 1%.

(1) Unless otherwise indicated, each beneficial owner has sole voting and investment power with respect to all of the units or shares attributed to him or her.

(2) Of the 3,300 class A common units deemed beneficially owned by Mr. Petty, 683 of such Class A common units are held in an account of his aunt, for which Mr. Petty has been granted power-of-attorney to effect trades. Of the 2,937 Listed Shares deemed beneficially owned by Mr. Petty, 915 shares are held in each of two Uniform Gifts to Minors Act custodial accounts for the benefit of two granddaughters. Mr. Petty is the custodian for each such account.

(3) Of the 9,500 Class A common units deemed beneficially owned by Mr. Westbrook, 8,000 Class A common units are held by The Westbrook Trust, for which Mr. Westbrook is the trustee and beneficiary, and 1,500 Class A common units are held by the Mary Ruth Trust, for which Mr. Westbrook is one of the trustees, along with his mother, who is also the beneficiary.

(4) Of the 22,000 Class A common units deemed beneficially owned by Mr. Letwin, 7,000 Class A common units are owned by Mr. Letwin's spouse.

Item 13. Certain Relationships and Related Transactions, and Director Independence

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

At December 31, 2008, our general partner had the following ownership interest in us:

	Quantity	Effective Ownership %
Direct ownership		
Class A common units representing limited partner interest	16,250,000	13.9%
Class B common units representing limited partner interest	3,912,750	3.4%
Class C units representing limited partner interest	6,449,315	5.5%
General Partner interest	—	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	2,542,527	2.2%
Total effective ownership	29,154,592	27.0%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2008, Enbridge Management owned 14,763,055 i-units, representing a 12.7% 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. The holders of our i-units and Class C units receive in-kind distributions under the Partnership Agreement. Our General Partner receives incremental incentive cash distributions on the portion of cash distributions that exceed certain target thresholds on a per unit basis 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 2008, we paid cash and incentive distributions to our general partner for its general partner ownership interest of approximately $43.7 million and cash distributions of $15.2 million in connection with its ownership of the Class B common units. The cash distributions we make to our general partner for its general partner ownership interest exclude an amount equal to two percent of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

IN-KIND DISTRIBUTIONS

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 Class A and Class B common units, we issue additional i-units to Enbridge Management in an amount determined by dividing the cash amount distributed per limited partner 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. In 2008, we distributed a total of 1,198,969 i-units to Enbridge Management and retained cash totaling approximately $54.2 million in connection with these in-kind distributions.

Holders of our Class C units receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distribution we pay to the holders of our Class A and Class B common units. We determine the additional Class C units we will issue by dividing the quarterly cash distribution per unit we pay on our Class A and Class B common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. In 2008, we distributed a total of 529,207 Class C units to our general partner in lieu of making cash distributions and retained cash totaling approximately $23.7 million in connection with these in-kind distributions.

GENERAL PARTNER CONTRIBUTIONS

Pursuant to our partnership agreement, our general partner is at all times required to maintain its two percent general partner ownership interest in us. During 2008, in connection with our issuances and sales in March 2008 of approximately 4.6 million Class A common units, and in December 2008 of 16.25 million Class A common units, our general partner contributed approximately $4.6 million and $10.2 million to us, respectively, to maintain its two percent general partner ownership interest.

OTHER RELATED PARTY TRANSACTIONS

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. We obtain managerial, administrative and operational services from our general partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Hungary Note Payable

As of December 31, 2008 and 2007, we had $130.0 million in amounts outstanding under notes payable to Enbridge Hungary Ltd., an affiliate of our general partner, which we refer to as the Hungary Note. In December 2007, we repaid $145.0 million of the original Hungary Note, including $8.8 million of accrued interest, with proceeds we received from entering into a new Hungary Note agreement with substantially the same terms and approximately $15 million from our existing cash. The new Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. Similar to the old Hungary Note, the new note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. Consistent with the original Hungary Note, the new Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The new Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes. We entered into the original Hungary Note agreement in connection with our acquisition of the Midcoast system in October 2002.

EUS Credit Agreement

In December 2007, we entered an unsecured revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge ("EUS Credit Agreement"). Enbridge is the indirect owner of Enbridge Energy Company, Inc., our general partner. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement as discussed above. Amounts borrowed under the EUS Credit

Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2008, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

Facilities Cost Reimbursement Agreement

In 2007, we entered into an agreement with Enbridge Pipelines Inc., a wholly-owned subsidiary of Enbridge, to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines Inc. As compensation for installing and operating these transportation facilities, Enbridge Pipelines Inc. makes annual payments to us on a cost of service basis. The income we accrued for providing these transportation services in 2008 and 2007 was approximately \$0.7 million and \$0.6 million, respectively.

Private Issuance of Class A Common units to General Partner

In December 2008, we issued and sold 16.25 million Class A common units to the General Partner in a private placement for a purchase price of \$30.76 per unit, or approximately \$500 million. Since the transaction was private it was exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The Class A common units represent limited partner ownership interests in the Partnership and increased the General Partner's ownership in the Partnership from approximately 15 percent to approximately 27 percent. The General Partner also contributed approximately \$10.2 million to us to maintain its two percent general partner interest. We used the proceeds to repay a portion of our outstanding Credit Facility borrowings that we use to finance our capital expansion projects and to repay \$25 million of our Senior Notes maturing on January 15, 2009. Since the transaction involved both the Partnership and our general partner, the board of directors of Enbridge Management determined that it was advisable to form a special committee of independent directors to evaluate the transaction. The special committee engaged independent legal counsel and an independent financial advisor to advise it regarding the transaction. The special committee then approved the transaction on behalf of the Partnership.

For further discussion of these and other related party transactions, refer to "Note 12—Related Party Transactions" in the consolidated financial statements beginning on Page F-2 of this Annual Report on Form 10-K.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or Enbridge Management, as appropriate. The board of directors then determines whether it is advisable to constitute a special committee of independent directors to evaluate the proposed transaction. If a special committee is appointed, the committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the special committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair to us and all of our unitholders.

Potential transactions with related persons that are not financially significant so as to require review by the board of directors are disclosed to the President of Enbridge Management and our general partner and reviewed for compliance with the Enbridge Statement on Business Conduct. The President may also consult with legal counsel in making such determination. If a related person transaction occurred and was later found not to comply with the Statement on Business Conduct, the transaction would be reported to the board of directors for further review and ratification or remedial action.

During 2008, we had the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- An affiliate of Enbridge which provides employee services to the Partnership continued a previously existing employment relationship with Jan Connelly, the sister of Jeffrey A. Connelly, a member of the Board of Directors. Ms. Connelly is employed in our Michigan office as the Manager, Origination. During 2008, she received total cash compensation of $189,959.33 and benefits estimated at approximately 37% of her base compensation for a total of $237,504.33.

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,	
	2008	2007
Audit fees[1]	$2,566,000	$2,453,000
Audit related fees[2]	792,000	—
Tax fees[3]	742,500	702,500
All other fees	—	—
Total	$4,100,500	$3,155,500

(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) Preliminary financial due diligence and audit services in connection with a transaction that the Partnership had been considering during 2008.

(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 2008 and 2007 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits and 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, 2008, 2007, and 2006.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2008, 2007, and 2006.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007, and 2006.

e. Consolidated Statements of Financial Position as of December 31, 2008 and 2007.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2008, 2007, and 2006.

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/ STEPHEN J.J. LETWIN
Stephen J.J. Letwin
(Managing Director)

Date: February 19, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 19, 2009 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ STEPHEN J.J. LETWIN
Stephen J.J. Letwin
Managing Director
(Principal Executive Officer)

/s/ MARK A. MAKI
Mark A. Maki
Vice President—Finance
(Principal Financial Officer)

/s/ TERRANCE L. MCGILL
Terrance L. McGill
President and Director

/s/ STEPHEN J. NEYLAND
Stephen J. Neyland
Controller

/s/ STEPHEN J. WUORI
Stephen J. Wuori
Executive Vice President—Liquids Pipelines and Director

/s/ JEFFREY A. CONNELLY
Jeffrey A. Connelly
Director

/s/ MARTHA O. HESSE
Martha O. Hesse
Director

/s/ GEORGE K. PETTY
George K. Petty
Director

/s/ DAN A. WESTBROOK
Dan A. Westbrook
Director

Index of 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 (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 of the Partnership's 2000 Form 10-K/A filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, filed on August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006).
3.4	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on January 3, 2008).
3.5	Amendment No. 2 to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 7, 2008).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 of the Partnership's 2000 Form 10-K/A filed on October 9, 2001).
4.2	Registration Rights Agreement, dated August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on August 16, 2006).
4.3	Registration Rights Agreement, dated April 2, 2007, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P., Tortoise Energy Infrastructure Corporation and Tortoise Energy Capital Corporation (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on April 2, 2007).
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.
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.
10.3	Contribution Agreement (incorporated by reference to Exhibit 10.1 of the Partnership's Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Registration Statement on Form S-1/A filed on September 24, 2002).
10.5	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of 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 (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 5, 2005).
10.8	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).

Exhibit Number	Description
10.9	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.10	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.11	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.12	Second Amended and Restated Credit Agreement, dated April 4, 2007, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on April 10, 2007).
10.13	Credit Agreement, dated December 18, 2007, between the Partnership, as Borrower, and Enbridge (U.S.), Inc., as Lender (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K, filed on December 19, 2007).
10.14	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.15	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.16	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.17	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.18	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 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.19*	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc.
10.20	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 (incorporated by reference to Exhibit 10.17 of the Partnership's 1996 Form 10-K filed February 28, 1997).
10.21	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program Phase II and Terrace Expansion Project (incorporated by reference to Exhibit 10.21 of the Partnership's 1998 Form 10-K filed on March 22, 1999).
10.22	Offer of Settlement dated December 21, 2005, as filed with the Federal Energy Regulatory Commission for approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy, Limited Partnership of the costs for the Southern Access Mainline Expansion and approval of the Offer of Settlement dated March 16, 2006 (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed July 31, 2007).
10.23	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.1 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K filed on October 20, 1998).
10.24	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K filed on October 20, 1998).

Exhibit Number	Description
10.25	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K filed on October 20, 1998).
10.26	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K filed on November 20, 2000).
10.27	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.4 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K filed on October 20, 1998).
10.28+	Executive Employment Agreement, dated April 14, 2003, between Stephen J.J. Letwin, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on May 3, 2006).
10.29+	Executive Employment agreement between Stephen J. Wuori and Enbridge Inc. dated April 14, 2003 (incorporated by reference to our Current Report on Form 8-K filed on January 28, 2008).
10.30+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.31	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.32	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.6 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.33	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.7 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.34	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on January 9, 2004).
10.35	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.36	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.37	Sixth Supplemental Indenture dated December 21, 2006 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 21, 2006).
10.38	Seventh Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on April 7, 2008).
10.39	Eighth Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on April 7, 2008).
10.40	Ninth Supplemental Indenture, dated December 22, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 22, 2008).

Exhibit Number	Description
10.41	Indenture for Subordinated Debt Securities dated as of September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.42	First Supplemental Indenture to the Indenture dated as of September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (including form of Note) (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on September 28, 2007).
10.43	Replacement Capital Covenant dated as of September 27, 2007 by Enbridge Energy Partners, L.P. in favor of the debtholders designated therein (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.44	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on February 10, 2005).
10.45	Class A Common Unit Purchase Agreement, dated November 17, 2008, between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on November 18, 2008).
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of 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. (incorporated by reference to Exhibit 99.1 of 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 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.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income and comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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 19, 2009

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2008	2007	2006
	(in millions, except per unit amounts)		
Operating revenue	$10,060.0	$7,282.6	$6,509.0
Operating expenses			
Cost of natural gas (Notes 6, 14 and 15)	8,572.9	6,246.9	5,514.6
Operating and administrative	535.1	434.3	364.8
Power	140.7	117.0	107.6
Depreciation and amortization (Note 7)	223.4	165.6	135.1
	9,472.1	6,963.8	6,122.1
Operating income	587.9	318.8	386.9
Interest expense	180.6	99.8	110.5
Other income	2.9	3.0	8.5
Income from continuing operations before income tax expense	410.2	222.0	284.9
Income tax expense (Note 16)	7.0	5.1	—
Income from continuing operations	403.2	216.9	284.9
Income from discontinued operations (Note 3)	—	32.6	—
Net income	$ 403.2	$ 249.5	$ 284.9
Net income allocable to limited partner units (Note 4)			
Income from continuing operations	$ 352.5	$ 179.9	$ 254.0
Income from discontinued operations	—	31.9	—
Net income allocable to limited partner units	$ 352.5	$ 211.8	$ 254.0
Basic and diluted earnings per limited partner unit (Note 4)			
Income from continuing operations	$ 3.63	$ 2.08	$ 3.62
Income from discontinued operations	—	0.37	—
Net income per limited partner unit (basic and diluted)	$ 3.63	$ 2.45	$ 3.62
Weighted average limited partner units outstanding	97.1	86.3	70.2
Cash distributions paid per limited partner unit	$ 3.880	$ 3.725	$ 3.700

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Net income	$403.2	$ 249.5	$284.9
Other comprehensive income (loss), net of tax benefit (expense) of $(1.8), $0.7 and $0.9, respectively (Note 15)	307.3	(104.8)	112.5
Comprehensive income	$710.5	$ 144.7	$397.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Cash provided by operating activities			
Net income	$ 403.2	$ 249.5	$ 284.9
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	223.4	165.6	135.1
Derivative fair value (gains) losses (Notes 14 and 15)	(68.8)	64.2	(64.4)
Gain on sale of net assets (Note 3)	—	(32.6)	—
Inventory market price adjustments (Note 6)	11.6	4.5	17.7
Other (Note 19)	25.5	1.8	7.8
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	56.1	(11.1)	(36.5)
Due from General Partner and affiliates (Note 12)	(13.3)	3.3	(10.4)
Accrued receivables	91.5	(82.3)	98.8
Inventory (Note 6)	46.0	2.0	1.1
Current and long term other assets (Notes 14 and 15)	10.2	(3.9)	(2.7)
Due to General Partner and affiliates (Note 12)	(3.6)	23.2	10.1
Accounts payable and other (Notes 2, 14 and 15)	(17.2)	(3.1)	4.3
Accrued purchases	(222.6)	73.5	(116.4)
Interest payable	13.1	9.5	4.4
Property and other taxes payable (Notes 2 and 16)	10.3	0.2	(2.0)
Settlement of interest rate derivatives (Note 15)	(22.1)	(0.9)	(10.2)
Net cash provided by operating activities	543.3	463.4	321.6
Cash used in investing activities			
Additions to property, plant and equipment (Note 12)	(1,375.4)	(1,980.2)	(864.4)
Changes in construction payables	(40.0)	83.6	30.4
Asset acquisitions, net of cash acquired (Note 3)	(11.7)	—	(33.3)
Proceeds from sale of net assets (Note 3)	—	133.0	0.2
Changes in restricted cash (Note 2 and 5)	(0.1)	—	—
Other	(1.1)	(1.4)	0.1
Net cash used in investing activities	(1,428.3)	(1,765.0)	(867.0)
Cash provided by financing activities			
Net proceeds from unit issuances (Notes 11 and 12)	731.6	628.8	509.6
Distributions to partners (Notes 11 and 12)	(286.7)	(245.4)	(227.4)
Net proceeds from issuances of long-term debt (Note 10)	1,286.7	592.8	297.6
Repayments of long-term debt (Note 10)	(56.0)	(31.0)	(31.0)
Net borrowings (repayments) under Credit Facility (Note 10)	(233.2)	400.0	—
Net commercial paper issuances (repayments) (Note 10)	(268.0)	(171.5)	111.4
Affiliate note borrowings (Notes 10 and 12)	—	130.0	—
Affiliate note repayments (Notes 10 and 12)	—	(136.2)	(20.0)
Net cash provided by financing activities	1,174.4	1,167.5	640.2
Net increase (decrease) in cash and cash equivalents	289.4	(134.1)	94.8
Cash and cash equivalents at beginning of year	50.5	184.6	89.8
Cash and cash equivalents at end of period	$ 339.9	$ 50.5	$ 184.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2008	December 31, 2007
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 2 and 5)	$ 339.9	$ 50.5
Restricted cash (Note 2 and 5)	0.1	—
Receivables, trade and other, net of allowance for doubtful accounts of $2.6 in 2008 and $1.9 in 2007	103.0	157.8
Due from General Partner and affiliates (Note 12)	40.5	27.2
Accrued receivables	507.3	598.8
Inventory (Note 6)	53.0	110.6
Other current assets (Notes 14 and 15)	80.7	14.8
	1,124.5	959.7
Property, plant and equipment, net (Note 7)	6,722.9	5,554.9
Goodwill (Note 8)	256.5	256.5
Intangibles, net (Note 9)	88.7	91.5
Other assets, net (Notes 14, 15 and 16)	108.3	29.0
	$8,300.9	$6,891.6
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 12)	$ 42.2	$ 45.8
Accounts payable and other (Notes 5, 13, 14 and 15)	225.3	400.4
Accrued purchases	381.2	603.8
Interest payable	34.0	20.9
Property and other taxes payable (Note 16)	32.8	22.5
Current maturities of long-term debt (Note 10)	420.7	31.0
	1,136.2	1,124.4
Long-term debt (Note 10)	3,223.4	2,862.9
Notes payable to affiliate (Note 12)	130.0	130.0
Other long-term liabilities (Notes 13, 14, 15 and 16)	84.4	202.8
	4,574.0	4,320.1
Commitments and contingencies (Note 13)		
Partners' capital (Note 11 and 12)		
Class A common units (76,088,834 and 55,238,834 at December 31, 2008 and 2007, respectively)	2,104.0	1,340.7
Class B common units (3,912,750 at December 31, 2008 and 2007)	85.0	72.9
Class C units (19,688,968 and 18,073,367 at December 31, 2008 and 2007, respectively)	886.5	874.1
i-units (14,763,055 and 13,564,086 at December 31, 2008 and 2007, respectively)	553.8	515.3
General Partner	84.7	62.9
Accumulated other comprehensive income (loss) (Notes 14 and 15)	12.9	(294.4)
	3,726.9	2,571.5
	$8,300.9	$6,891.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	For the year ended December 31,					
	2008		2007		2006	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Class A common units:						
Beginning balance	55,238,834	$1,340.7	49,938,834	$1,141.7	49,938,834	$1,142.4
Net income allocation	—	217.0	—	130.1	—	184.1
Allocation of proceeds and issuance costs from unit issuance	20,850,000	774.1	5,300,000	264.9	—	—
Distributions	—	(227.8)	—	(196.0)	—	(184.8)
Ending balance	76,088,834	2,104.0	55,238,834	1,340.7	49,938,834	1,141.7
Class B common units:						
Beginning balance	3,912,750	72.9	3,912,750	67.6	3,912,750	67.2
Net income allocation	—	14.7	—	9.8	—	14.9
Allocation of proceeds and issuance costs from unit issuance	—	12.6	—	10.0	—	—
Distributions	—	(15.2)	—	(14.5)	—	(14.5)
Ending balance	3,912,750	85.0	3,912,750	72.9	3,912,750	67.6
Class C units:						
Beginning balance	18,073,367	874.1	11,070,152	509.8	—	—
Net income allocation	—	69.0	—	39.9	—	10.4
Allocation of proceeds and issuance costs from unit issuance	—	(56.6)	5,930,792	324.4	10,869,565	499.4
Distributions	1,615,601	—	1,072,423	—	200,587	—
Ending balance	19,688,968	886.5	18,073,367	874.1	11,070,152	509.8
i-units:						
Beginning balance	13,564,086	515.3	12,674,148	466.3	11,704,948	421.7
Net income allocation	—	51.8	—	32.0	—	44.6
Allocation of proceeds and issuance costs from unit issuance	—	(13.3)	—	17.0	—	—
Distributions	1,198,969	—	889,938	—	969,200	—
Ending balance	14,763,055	553.8	13,564,086	515.3	12,674,148	466.3
General Partner:						
Beginning balance		62.9		47.6		34.6
Net income allocation		50.7		37.7		30.9
Allocation of proceeds and issuance costs from unit issuance		—		—		—
General Partner contribution		14.8		12.5		10.2
Distributions		(43.7)		(34.9)		(28.1)
Ending balance		84.7		62.9		47.6
Accumulated other comprehensive loss:						
Beginning balance		(294.4)		(189.6)		(302.1)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		140.5		94.8		78.3
Unrealized gain (loss) on derivative financial instruments		166.8		(199.6)		34.2
Ending balance		12.9		(294.4)		(189.6)
Partners' capital at December 31,		$3,726.9		$2,571.5		$2,043.4

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

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. (the "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 "OLP") 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 United States to eastern Canada.

We are a geographically and operationally diversified organization, providing crude oil gathering, transportation and storage services, and natural gas gathering, treating, processing, marketing and transportation services 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 capital accounts consist of general partner interests and limited partner interests. Our limited partner interests include Class A and Class B common units, Class C units and i-units, which we collectively refer to as the limited partner units. At December 31, 2008 and 2007, our ownership was distributed as follows:

	2008	2007
Class A common units owned by the public	51.2%	59.6%
Class A common units owned by our General Partner	13.9%	—
Class B common units owned by our General Partner	3.4%	4.2%
Class C units owned by our General Partner	5.5%	6.4%
Class C units owned by institutional investors	11.3%	13.1%
i-units owned by Enbridge Management[(1)]	12.7%	14.7%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) The General Partner owns 17.2% of the total i-units owned by Enbridge Management.

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, is a Delaware limited liability company that was formed in May 2002. Our general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of its directors. 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 derives all of its earnings from this investment.

Enbridge Management's principal activity is managing 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 its common shares are publicly traded on the NYSE in the United States and the Toronto Stock Exchange in Canada under the symbol "ENB." Enbridge is a leader in energy transportation and distribution in North America, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution. Enbridge also has international interests located in Latin America. At December 31, 2008 and 2007, Enbridge and its consolidated subsidiaries owned an effective 27.0 percent and 15.1 percent 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 1,900 miles and includes approximately 3,800 miles of pipe, has been in operation for over 55 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 active crude oil pipelines, including the FERC-regulated Ozark pipeline and approximately 16.7 million barrels of storage capacity, which serve 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 predominantly located in active producing basins in east and north Texas, as well as the Texas panhandle and western Oklahoma. Our Natural Gas segment includes nine natural gas treating plants and 24 natural gas processing plants at December 31, 2008, excluding plants that are inactive. In addition, our Natural Gas segment includes approximately 11,700 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide.

At December 31, 2008, our Natural Gas segment also included three FERC-regulated natural gas transmission pipeline systems located in the Southeast 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 income on gas purchased at the wellhead, and provide value-added services to customers.

Our Marketing business purchases third-party pipeline transportation capacity which provides us and 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 natural gas and NGL products.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our preparation of these 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.

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 accounts and transactions have been eliminated in consolidation.

Comparative Amounts

We have made reclassifications to the amounts reported in our prior year consolidated statement of financial position and our consolidated statements of cash flows to conform to our current year presentation. We reclassified $2.8 million from "Environmental liabilities" to "Other long-term liabilities" in our December 31, 2007 consolidated statement of financial position. In addition, we reclassified $4.9 million from "Current income taxes payable" to "Property and other taxes payable" in our December 31, 2007 consolidated statement of cash flows.

Accounting for Regulated Operations

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

Revenue Recognition and the Estimation of 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 our crude oil storage assets. The tariffs established for our interstate pipelines 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. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectability is reasonably assured. We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on throughput volumes. We recognize revenues as storage services are rendered, when pricing is determinable and collectability is reasonably assured. In the Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk.

Natural Gas

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectability 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 our Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on both our FERC-regulated interstate natural gas transmission pipeline systems and some of our intrastate pipelines systems. Customers paying these fees typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. Additional revenues from our intrastate pipelines are derived from the bundled sales of natural gas and transmission services.

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 hedge a significant amount of our exposure to commodity price risk to support the stability of our cash flows. Refer to Note 15 for more information about the derivative activities we use to mitigate this commodity price risk.

These other types of arrangements are categorized as follows:

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements discussed below 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 at market prices, the resulting residue gas. 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 an energy content equivalent to the original raw gas we received as measured in British thermal units, or Btu.

- 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.

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 revenues on natural gas purchased at the wellhead, and to provide other services valued by our 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 revenues 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. We recognize revenues upon delivery of natural gas and NGLs to our customers, when services are rendered, pricing is determinable and collectability is reasonably assured.

Estimation of Revenue and Cost of Natural Gas

For our natural gas and marketing 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, 2008, 2007 and 2006. 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 present cash accounts that are restricted as to withdrawal or usage as "Restricted cash" on our consolidated statements of financial position.

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not been presented to the financial institution are included in "Accounts payable and other" on our consolidated statements of financial position.

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. Collectability 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. We record all product inventories at the lower of our cost as determined on a weighted average basis, or market. Our 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, including any adjustments recorded to reduce inventory to market value.

Materials and supplies inventory is either used during operations and charged to operating expense as incurred, or used for capital projects and new construction, and capitalized to property, plant and equipment.

Oil Measurement Adjustments

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum pipelines. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- Degradation, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are inherently difficult 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 adjustments is especially difficult for us because of the length of our 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 systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement 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 "Accrued receivables" and "Accrued purchases" on our consolidated statements of financial position 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 replaced, improved, or the useful lives have been extended; 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, including any planned major maintenance activities, 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 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 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 a pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Regulatory guidance issued by the FERC requires 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 adopted this guidance prospectively in January 2006 for all our pipeline systems. 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 continue to be capitalized. We typically expense the cost of initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects consistent with industry practice and the regulatory guidance issued by the FERC. However, we capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life 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 net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we 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 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, the market and business environments to identify indicators that could 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 as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, 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. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the 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.

Pursuant to the provisions of SFAS No. 142, *"Goodwill and Other Intangible Assets,"* we do not amortize goodwill, but test it 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 be impaired. In testing goodwill for impairment, we make critical assumptions that include but are not limited to: 1) projections of future financial performance, which include commodity price and volume assumptions, 2) the expected growth rate of our Natural Gas and Marketing assets, 3) residual value of the assets and 4) our weighted average cost of capital. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value of goodwill. At the time we determine that an impairment has occurred, we will reduce the carrying value of goodwill to its fair value. We have not identified nor have we recognized any goodwill impairments during the years ended December 31, 2008, 2007 or 2006**.**

Intangibles, Net

Our intangible assets consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our 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 and its carrying amount exceeds its fair value, the intangibles are written down to their fair value. We did not identify nor recognize any impairment of our intangible assets for the years ended December 31, 2008, 2007, or 2006.

Other Assets

Other assets primarily include deferred financing costs, which we amortize on a straight-line basis over the life of the related debt to interest expense on our consolidated statements of income. Amortization of these costs on a straight-line basis approximates the amortization computed using the effective interest method.

Income Taxes

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to partnerships by the States of Texas and Michigan. The Texas tax is computed on our modified gross margin. The Michigan tax consists of two different taxes that are based on net income and modified gross receipts. We have determined these taxes to be income taxes under the provisions of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("SFAS No. 109").

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. We record the impact of changes in tax legislation on deferred income tax liabilities and assets in the period the legislation is enacted.

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.

Accounting for Uncertainty in Income Taxes

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement 109,* or FIN 48. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109. We implemented FIN 48 during the first quarter of 2007. Our adoption of FIN 48 did not materially affect our operating results, financial position or cash flows.

Fair Value Measurements

We adopted prospectively the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. We define fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We employ a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those assets and liabilities that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources. (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include debt and derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value; however, the cost of obtaining the information is prohibitive.

The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third party investment dealers who actively make markets in our debt securities, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. Our assets are adjusted for the non-performance risk of our counterparties using their credit default swap spread rates, which are updated quarterly. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and are also adjusted quarterly based on current default swap spread rates on our outstanding indebtedness. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

Our derivative contracts can be exchange-traded or over-the counter ("OTC"). We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of our fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to lacking binding broker quotes to corroborate pricing data. Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or we revise our interpretation of Level 2 criteria in practice to include non-binding market corroborated data.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. In accordance with Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), we record all derivative financial instruments on our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under SFAS 133, the accounting treatment depends on the intended use and designation of each instrument. 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 fair market value is recorded as a component of "Interest expense" in the consolidated statements of income.

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by 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 or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment that we use are cash flow hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

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, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations 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.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges 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 fair market value is recognized immediately in earnings. We determine the change in fair market value of financial instruments designated and qualifying as fair value hedges each period which we record in earnings. In addition, we calculate the change in the fair market value of the hedged item which is also recorded in 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 use of the mark-to-market method of accounting as required under GAAP for derivative financial instruments that do not qualify for hedge accounting. We use short-term, highly liquid derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments do not qualify for hedge accounting treatment under SFAS No. 133, and as a result we record changes in fair value of these instruments on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying indices, primarily commodity prices.

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 in "Accounts payable and other" and "Other long-term liabilities" in the statements of financial position 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. We typically expense legal costs associated with loss contingencies as such costs are incurred.

Asset Retirement Obligations

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 the cost of abandoning or retiring a pipeline system. 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 consumption of those resources by end users. 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 record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value 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 ARO 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 an ARO when assets are taken out of service or otherwise abandoned.

We did not record any additional AROs for the years ended December 31, 2008 and 2007. We recorded accretion expense of $0.1 million, $0.2 million and $0.2 million, respectively, in our consolidated statements of income for the years ended December 31, 2008, 2007 and 2006 for previously recorded asset retirement obligation liabilities.

No assets are legally restricted for purposes of settling our ARO for each of the years ended December 31, 2008 and 2007. Following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2008 and 2007:

	2008	2007
	(in millions)	
Balance at beginning of period	$2.9	$ 3.8
Disposal of KPC	—	(1.1)
Accretion expense	0.1	0.2
Balance at end of period	$3.0	$ 2.9

Recent Accounting Pronouncements Not Yet Adopted

Business Combinations

In December 2007, the Financial Accounting Standards Board, or FASB, issued Statement No. 141(R), *Business Combinations*, which we refer to as SFAS No. 141(R). The new standard retains the fundamental requirements in FASB Statement No. 141, *Business Combinations*, that the acquisition method of accounting (previously referred to as the *purchase method*), be used for all business combinations and for an acquirer to be identified for each business combination. Among other items, SFAS No. 141(R) requires the following:

- Assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date are to be measured at their fair values as of that date.
- Costs associated with effecting an acquisition and restructuring costs the acquirer was not obligated to incur are recognized separately from the business combination.
- Assets acquired and liabilities assumed arising from contractual contingencies as of the acquisition date are measured at their acquisition-date fair values.
- Noncontractual contingencies as of the acquisition date are measured at the acquisition-date fair values only if it is more likely than not that they meet the definition of an asset or liability in FASB Statements of Financial Accounting Concepts ("SFAC") Statement No. 6, *Elements of Financial Statements*.
- Assets and liabilities arising from contingencies are to be reported at the acquisition-date fair value absent new information about the possible outcome, however, when new information becomes available, liabilities are measured at the higher of the acquisition date fair value or the FASB Statement No. 5, *Accounting for Contingencies* ("SFAS No. 5") amount while assets are measured at the lower of the acquisition date fair value or the best estimate of the future settlement amount.
- Goodwill as of the acquisition date is determined as the excess of the fair value of the consideration transferred plus the fair value of any noncontrolling interest plus the fair value of previously held equity interests less the fair values of the identifiable net assets acquired.
- Recognition of a gain in earnings attributable to the acquirer when the total acquisition date fair value of the identifiable net assets acquired exceed the fair value of the consideration transferred plus any noncontrolling interest in the acquiree.
- Contingent consideration at the acquisition date is measured at its fair value at that date.
- Retroactively recognize adjustments made during the measurement period (not more than one year from the acquisition date) as if the accounting had occurred on the acquisition date.

SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and early adoption is not permitted. The provisions of this statement will require us to expense certain costs associated with acquisitions that were previously permitted to be capitalized which may affect our operating results in periods that we complete an acquisition.

Noncontrolling Interests

In December 2007, the FASB issued Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* ("SFAS No. 160"), to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for deconsolidation of a subsidiary. Among other provisions, SFAS No. 160 requires the following:

- The ownership in subsidiaries held by parties other than the parent be presented in the consolidated statement of financial position within equity, but separate from the parent's equity.
- The amount of consolidated net income attributable to the parent and the noncontrolling interest be presented on the face of the consolidated statement of income.

- Changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary are accounted for as equity transactions.
- Any retained noncontrolling equity investment in a subsidiary that is deconsolidated be initially measured at fair value.
- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

SFAS No. 160 is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2008, and early adoption is prohibited. SFAS No. 160 requires prospective adoption as of the beginning of the fiscal year in which the provisions are initially applied, except for the presentation and disclosure requirements which shall be applied retrospectively for all periods presented. Our adoption of this standard will not have a material effect on our results of operations, cash flows, or financial position.

Derivative Instruments and Hedging Activities

In March 2008, the FASB issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF, reached consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, Earning per Share. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We do not expect the adoption of the pronouncement to have a significant effect on our computation of earnings per unit per limited partner.

3. ACQUISITIONS AND DISPOSITIONS

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

2008 Acquisitions

During 2008, we completed two separate acquisitions totaling $11.7 million, the fair value of which we allocated entirely to “Property, plant and equipment” in our consolidated statement of financial position. We included the results of operations for the assets acquired in our Natural Gas segment from the acquisition date.

2007 KPC Disposition

In November 2007, we sold our Kansas pipeline system, or KPC, with a net asset value of approximately $100.4 million, including $9.2 million of goodwill, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. The area in which KPC operates is not strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the years ended December 31, 2007 and 2006. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

2006 Oakhill Acquisition

In April 2006, we acquired, for $33.3 million in cash, an 80-mile natural gas pipeline that is complementary to our existing East Texas system. This pipeline provides approximately 100 million cubic feet per day, or MMcf/d, of additional transportation capacity and interconnects with approximately 65 central receipt points.

The purchase price and the allocation to assets acquired and liabilities assumed are as follows in millions of dollars:

Purchase Price:	
Cash paid, including transaction costs	$33.3
Allocation purchase price:	
Property, plant and equipment, including construction in progress	13.0
Intangibles	12.8
Goodwill	7.5
Total	$33.3

4. NET INCOME PER LIMITED PARTNER UNIT

We compute net income per limited partner unit by dividing net income, after deducting our allocation to the General Partner, by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities, therefore basic and diluted earnings per unit amounts are equal. Net income per limited partner unit was determined as follows:

	For the year ended December 31,		
	2008	2007	2006
	(in millions, except per unit amounts)		
Income from continuing operations	$403.2	$216.9	$284.9
Income from discontinued operations	—	32.6	—
Net income	$403.2	$249.5	$284.9
Allocations to the General Partner:			
Income from continuing operations	(8.1)	$ (4.3)	$ (5.7)
Incentive distributions	(42.4)	(32.5)	(25.1)
Historical cost depreciation adjustments	(0.2)	(0.2)	(0.1)
	(50.7)	(37.0)	(30.9)
Income from discontinued operations	—	(0.7)	—
	$ (50.7)	$ (37.7)	$ (30.9)
Allocations to limited partner units:			
Income from continuing operations	$352.5	$179.9	$254.0
Income from discontinued operations	—	31.9	—
	$352.5	$211.8	$254.0
Basic and diluted earnings per limited partner unit:			
Income from continuing operations	$ 3.63	$ 2.08	$ 3.62
Income from discontinued operations	—	0.37	—
Net income per limited partner unit (basic and diluted)	$ 3.63	$ 2.45	$ 3.62
Weighted average limited partner units outstanding	97.1	86.3	70.2

5. CASH AND CASH EQUIVALENTS

Obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $30.5 million at December 31, 2008 and $38.5 million at December 31, 2007 are included in "Accounts payable and other" on our consolidated statements of financial position.

In September 2008, following the bankruptcy filing by Lehman Brothers Holdings Inc. ("Lehman"), Lehman Brothers Bank, FSB ("Lehman BB"), as discussed in Note 10, ceased to honor its funding commitment under the terms of our Second Amended and Restated Credit Agreement ("Credit Facility"). As a result, Bank of America, N.A., as administrative agent to our Credit Facility, required us to provide cash collateral for a portion of the letters of credit we have outstanding under the terms of our Credit Facility that would have been obligations of Lehman BB. At December 31, 2008 we had $0.1 million of cash collateral which is presented as "Restricted cash" on our consolidated statements of financial position. We may, from time to time, be required to provide cash collateral for letters of credit we have outstanding to support any funding requests for the portion of our Credit Facility not being funded by Lehman BB.

6. INVENTORY

Inventory is comprised of the following:

	December 31, 2008	December 31, 2007
	(in millions)	
Materials and supplies	$ 3.9	$ 3.9
Liquids inventory	7.1	6.7
Natural gas and NGL inventory	42.0	100.0
	$53.0	$110.6

Our inventory at December 31, 2008 and 2007 is net of charges totaling $11.6 million and $4.5 million, respectively that we recorded to reduce the cost basis of our natural gas and NGL inventory to reflect market value. The lower of cost or market adjustments are included in the "Cost of natural gas" of our Natural Gas and Marketing segments on our consolidated statements of income.

7. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	Depreciation Rates [1]	December 31, 2008	December 31, 2007
		(in millions)	
Land	—	$ 17.9	$ 14.3
Rights-of-way	1.5% - 6.4%	437.1	345.8
Pipelines	1.5% - 7.0%	4,327.8	2,703.2
Pumping equipment, buildings and tanks	1.5% - 14.3%	995.4	854.7
Compressors, meters, and other operating equipment	1.5% - 20.0%	639.3	536.1
Vehicles, office furniture and equipment	1.5% - 33.3%	153.0	123.3
Processing and treating plants	2.7% - 4.0%	343.1	200.4
Construction in progress	—	1,057.0	1,813.9
Total property, plant and equipment		7,970.6	6,591.7
Accumulated depreciation		(1,247.7)	(1,036.8)
Property, plant and equipment, net		$ 6,722.9	$ 5,554.9

(1) We have assets included in the above table that are highly depreciated, which yield depreciation rates that suggest these assets have significant remaining useful lives, but in fact have little remaining net book value in relation to their expected service lives.

8. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2008 and 2007 are as follows:

	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
December 31, 2006	$—	$245.3	$20.4	$—	$265.7
Disposition	—	(9.2)	—	—	(9.2)
December 31, 2007 and 2008	$—	$236.1	$20.4	$—	$256.5

In November 2007 we sold our KPC assets to an unrelated party for $133 million. In connection with the sale, we disposed of $9.2 million of goodwill associated with this business which reduced the gain we realized from the sale.

We test our goodwill for impairment annually primarily by using a discounted cash flow analysis. In addition, we also consider overall market capitalization of our business, earnings before interest and taxes ("EBITDA") data, and other factors. At June 30, 2008 we completed our annual goodwill impairment test which did not indicate the existence of impairment to goodwill associated with any of our reporting units. Although our market capitalization exceeded the book value of our equity at December 31, 2008, significant deterioration in global economic conditions and a decline in commodity prices caused us to retest our goodwill for impairment as of December 31, 2008. As a result, we updated the critical assumptions in our analysis to consider changes in market conditions since June 30, 2008. Key assumptions include the following:

1) A weighted average cost of capital from 10% to 12%;
2) An annual growth rate for our Natural gas and Marketing businesses of approximately 3.0% to 4.0%;
3) A capital structure consisting of approximately 50% debt and 50% equity; and
4) A long-term commodity price forecast using recent pricing information.

The December 31, 2008 impairment testing of our goodwill did not indicate the existence of impairment to the goodwill associated with our reporting units. We have not observed any further events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2008.

9. INTANGIBLES

The following table provides the gross carrying value, accumulated amortization and activity affecting amounts comprising each of our major classes of intangible assets.

	Gross Carrying Amount			Accumulated Amortization			
	Natural Gas Intangibles[2]	Other	Intangible Assets Gross	Natural Gas Intangibles[2]	Other	Accumulated Amortization Gross	Intangible Assets, Net
				(in millions)			
December 31, 2006	$104.1	$ 6.7	$110.8	$(12.7)	$(0.3)	$(13.0)	$97.8
Additions	—	2.9	2.9	—	—	—	2.9
Dispositions[1]	(5.8)	—	(5.8)	1.1	—	1.1	(4.7)
Amortization	—	—	—	(4.1)	(0.4)	(4.5)	(4.5)
December 31, 2007	98.3	9.6	107.9	(15.7)	(0.7)	(16.4)	91.5
Additions	—	1.6	1.6	—	—	—	1.6
Amortization	—	—	—	(3.9)	(0.5)	(4.4)	(4.4)
December 31, 2008	$ 98.3	$11.2	$109.5	$(19.6)	$(1.2)	$(20.8)	$88.7

(1) We disposed of customer contract intangibles of $4.7 million in connection with the sale of KPC.

(2) Natural gas intangibles include customer contracts and natural gas supply opportunities discussed below.

Our customer contracts are comprised entirely of natural gas purchase and sale agreements associated with our Natural Gas and Marketing segments. We amortize our customer contracts on a straight-line basis over the weighted average useful life of the underlying reserves at the time of acquisition, which approximates 25 years.

We obtained the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition and relate entirely to 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. We are amortizing the natural gas supply opportunities over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which approximates 25 years.

Our other column is comprised of contributions we made in aid of construction for our Natural Gas and Liquids business. We made contributions to third parties for construction of electrical infrastructure to provide utility services for our Lakehead system and for interconnections between our natural gas systems and third-party pipelines and the related measurement equipment.

We estimate the aggregate amortization expense associated with our intangibles for each of the five succeeding years through December 31, 2013 to approximate $4.6 million per year.

10. DEBT

The following table presents the primary components of our outstanding indebtedness and the weighted average interest rates associated with each component at the end of each period presented, before the effect of our interest rate hedging activities as discussed in Notes 14 and 15:

		December 31,			
		2008		2007	
	Maturity	Rate	Dollars	Rate	Dollars
	(dollars in millions)				
First Mortgage Notes	2011	9.15%	$ 93.0	9.15%	$ 124.0
Credit Facility	2013	3.80%	166.8	5.22%	400.0
Commercial Paper[1]	2013	—	—	5.36%	268.5
Senior Notes	2009-2038	6.75%	2,985.0	5.69%	1,702.1
Junior Subordinated Notes	2067	8.05%	399.3	8.05%	399.3
			3,644.1		2,893.9
Current maturities and short-term debt			(420.7)		(31.0)
Long-term debt			$3,223.4		$2,862.9

[1] Individual issuances 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 Enbridge Energy, Limited Partnership, (the "OLP"), and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. "Property, plant and equipment, net," associated with the OLP was $3,456.2 million and $2,555.5 million at December 31, 2008 and 2007, 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 12) for the immediately preceding calendar quarter. We would be required to pay a redemption premium pursuant to the Notes agreements should we elect to repay the Notes prior to their stated maturity.

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 percent of the prospective Notes interest payments for the immediately following quarter and an amount for Notes sinking fund repayments. At December 31, 2008 and 2007, there was no required debt service reserve, as we have made all required interest and sinking fund payments.

Credit Facility

Our Credit Facility among other conditions includes the following terms: (i) a maximum principal amount of credit available to us at any one time of $1.25 billion; (ii) the right to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion; (iii) no sublimit on letters of credit; and (iv) a five-year facility that initially matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity. In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date from April 4, 2012 to April 4, 2013.

In September 2008, Lehman filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Lehman is the parent of Lehman BB, one of the committed lenders to our Credit Facility. Lehman BB has commitments of $82.5 million that we currently cannot access, which effectively reduces the amounts available to us under our Credit Facility to $1,167.5 million and the maximum increase in principal amount of credit available to us we can request to approximately $1.4 billion. The remaining lenders under our Credit Facility continue to honor our funding requests.

At December 31, 2008, we had $166.8 million outstanding under our Credit Facility at a weighted average interest rate of 3.80% and letters of credit totaling $1.8 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. Excluding the commitments from Lehman BB, at December 31, 2008, we could borrow $998.9 million under the terms of our Credit Facility, determined as follows:

	2008
	(in millions)
Total credit available under Credit Facility	$1,250.0
Less: Amounts outstanding under Credit Facility	(166.8)
Balance of letters of credit outstanding	(1.8)
Principal amount of commercial paper issuances	—
Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at December 31	$ 998.9

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.50 to 1.0 for periods ending on or before March 31, 2009; a ratio of 5.25 to 1.0 thereafter, for periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At December 31, 2008, our leverage ratio was approximately 3.8 as computed on the terms of our Credit Facility. 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.

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 year ended December 31, 2008 and 2007, we net settled borrowings of approximately $1,483.3 million and $180 million, respectively, on a non-cash basis and none during the year ended December 31, 2006.

Commercial Paper Program

We have an established commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. In late 2008, the credit rating on our commercial paper provided by Standard & Poor's was downgraded from A-2 to A-3, which effectively precludes us from accessing the commercial paper market until such time as the rating improves. We generally accessed the commercial paper market to provide temporary financing for our operating activities, capital expenditures and acquisitions. At December 31, 2008 we had no commercial paper outstanding compared to December 31, 2007 when we had $268.5 million outstanding, net of unamortized discount $1.5 million, at weighted average interest rate of 5.36%.

Senior Notes

All of our Senior Notes, other than the Zero Coupon Notes discussed below, pay interest semi-annually and have varying maturities and terms as presented in the following table. 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 unsecured and unsubordinated indebtedness. We have granted the holders of our Senior Notes due 2019 an option to require us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100 percent of the principal amount of the notes tendered plus accrued and unpaid interest. The interest rates set forth in this table represent the interest rates as set forth on the face of each note agreement without consideration to any discount or interest rate hedging activities.

		December 31,	
	Interest Rate	2008	2007
		(in millions)	
Senior Notes due 2009	4.000%	$ 175.0	$ 200.0
Senior Notes due 2012	7.900%	100.0	100.0
Senior Notes due 2013	4.750%	200.0	200.0
Senior Notes due 2014	5.350%	200.0	200.0
Senior Notes due 2016	5.875%	300.0	300.0
Senior Notes due 2018	7.000%	100.0	100.0
Senior Notes due 2018	6.500%	400.0	—
Senior Notes due 2019	9.875%	500.0	—
Senior Notes due 2028	7.125%	100.0	100.0
Senior Notes due 2033	5.950%	200.0	200.0
Senior Notes due 2034	6.300%	100.0	100.0
Senior Notes due 2038	7.500%	400.0	—
Senior, unsecured zero coupon notes due 2022	5.358%	214.7	203.6
		2,989.7	1,703.6
Unamortized Discount		(4.7)	(1.5)
		$2,985.0	$1,702.1

Zero Coupon Senior Notes

In August 2007, we received net proceeds of approximately $200 million from a private placement of our senior, unsecured zero coupon notes due 2022 (the “Zero Coupon Notes”), which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in “Long-term debt” at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at December 31, 2008 includes $11.1 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called Zero Coupon Notes. Currently, the carrying amount is included in “Current maturities of long-term debt.” The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to fund a portion of our capital expansion projects.

Junior Subordinated Notes

In September 2007, we issued and sold $400 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes. We received proceeds of approximately $393 million, net of underwriting discounts, commissions and offering expenses. We used the net proceeds to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to finance a portion of our capital expansion projects.

The Junior Notes represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, from September 27, 2007 to October 1, 2017, payable semi-annually in arrears on April 1 and October 1 of each year beginning April 1, 2008. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a "make-whole" redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

Interest

For the years ended December 31, 2008, 2007, and 2006, our interest cost is comprised of the following:

	For the year ended December 31,		
	2008	2007	2006
	(dollars in millions)		
Interest expense	$180.6	$ 99.8	$110.5
Interest capitalized	41.0	47.4	10.7
Interest cost incurred	$221.6	$147.2	$121.2
Interest paid	$193.1	$125.8	$109.7

Maturities of Third Party Debt

The scheduled maturities of outstanding third party debt, excluding any discounts and the market value of interest rate swaps, at December 31, 2008, are summarized as follows in millions:

2009	$ 420.7
2010	31.0
2011	31.0
2012	600.0
2013	366.8
Thereafter	2,200.0
Total	$3,649.5

11. PARTNERS' CAPITAL

Our capital accounts are comprised of a two percent general partner interest and 98 percent limited partner interests. Our limited partner interests include Class A common units, Class B common units, Class C 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. We refer to our Class A common units and Class B common units collectively as common units. 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, 2008, 2007 and 2006. The proceeds from each of our offerings were generally used to repay issuances of commercial paper or amounts outstanding under our credit facilities, which we initially borrowed to finance our capital expansion projects and acquisitions, or to repay other outstanding obligations. Any proceeds we received in excess of amounts used to repay issuances of commercial paper and credit facility borrowings were temporarily invested for use in future periods to fund additional expenditures associated with our capital expansion projects.

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 units and per unit amounts)			
2008					
December[3]	16,250,000	$30.760	$499.6	$10.2	$509.8
March	4,600,000	49.000	217.2	4.6	221.8
2008 Totals	20,850,000		$716.8	$14.8	$731.6
2007					
May	5,300,000	$58.000	$301.9	$ 6.1	$308.0
2006					

We did not issue any Class A common units during 2006.

(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.

(3) All Class A common units from the December 2008 issuance were issued to our General Partner.

Class B common units

Our outstanding Class B common units are held entirely by our general partner and have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

Class C units

Our outstanding Class C units have voting and other non-economic rights that are substantially similar to our Class A and Class B common units, but currently receive quarterly distributions in-kind rather than in cash. On August 15, 2009, all of our outstanding Class C units will convert into Class A common units on a one-for-one basis, subject to the satisfaction of certain conditions as set forth in our partnership agreement.

In April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We received proceeds of approximately $314.4 million, net of expenses associated with the private placement. In addition, our general partner contributed approximately $6.4 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion program.

In August 2006, we issued and sold 5.4 million Class C units to our general partner and 5.4 million Class C units to CDP for a purchase price of $46.00 per unit in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We received proceeds of approximately $500 million, net of expenses associated with the private placement. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest.

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

Our partnership agreement requires us to distribute 100 percent 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 cash requirements less cash disbursements and amounts retained by us. Enbridge Management, as delegate of our general partner under the delegation of control agreement, computes the amount of our "Available Cash." Typically, the General Partner and owners of our common units will receive distributions in cash. However, we also retain reserves 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). We make distributions 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 our 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 are generally made 98.0 percent to holders of our limited partner units and two percent to our general partner. However, distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of distributions to the unitholders are achieved. The incentive distributions payable to the General Partner are 15.0 percent, 25.0 percent and 50.0 percent of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per limited partner units, respectively. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead, will distribute additional i-units such that the cash is retained and used in our business. Similarly, until August 15, 2009, we will distribute additional Class C units to the holders of our Class C units in lieu of cash distributions, which will be retained and used in our business. Further, we retain an additional amount equal to two percent of the i-unit and Class C unit distributions from the General Partner to maintain its two percent general partner interest in us.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to our 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 listed and voting shares that are then outstanding. The amount of this increase 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 our general partner.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units will increase automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units is treated as if it had actually been distributed for purposes of determining the distributions to be made to our general partner.

After August 15, 2009, subject to conditions set forth in our partnership agreement, our Class C units will convert into Class A common units on a one-for-one basis and will receive quarterly cash distributions equal to those paid to the holders of our common units. If our Class C units are not converted, the holders of our Class C units will receive quarterly cash distributions equal to 115 percent of those paid to the holders of our common units. Prior to conversion, holders of our Class C units will not be entitled to receive any quarterly cash distributions until the holders of our common units have received a quarterly cash distribution of $0.59 per common unit.

The following table sets forth our distributions, as approved by Enbridge Management's board of directors for each period in the years ended December 31, 2008, 2007 and 2006.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(1)]	Amount of Distribution of Class C units to Class C unit Holders[(2)]	Retained from General Partner[(3)]	Distribution of Cash
			(in millions, except per unit amounts)					
2008								
October 13	November 6	November 14	$0.990	$108.8	$14.3	$18.9	$0.7	$ 74.9
July 28	August 6	August 14	0.990	108.0	13.9	18.6	0.7	74.8
April 28	May 7	May 15	0.950	102.2	13.1	17.5	0.6	71.0
January 28	February 6	February 14	0.950	96.7	12.9	17.2	0.6	66.0
				$415.7	$54.2	$72.2	$2.6	$286.7
2007								
October 29	November 6	November 14	$0.950	$ 96.0	$12.7	$16.8	$0.6	$ 65.9
July 27	August 6	August 14	0.925	92.6	12.1	16.2	0.6	63.7
April 26	May 7	May 15	0.925	86.6	11.9	15.9	0.6	58.2
January 26	February 6	February 14	0.925	80.0	11.7	10.2	0.5	57.6
				$355.2	$48.4	$59.1	$2.3	$245.4
2006								
October 27	November 6	November 14	$0.925	$ 79.6	$11.5	$10.1	$0.4	$ 57.6
July 28	August 4	August 14	0.925	68.1	11.3	—	0.2	56.6
April 27	May 5	May 15	0.925	67.8	11.0	—	0.2	56.6
January 30	February 7	February 14	0.925	67.6	10.8	—	0.2	56.6
				$283.1	$44.6	$10.1	$1.0	$227.4

(1) We issued 1,198,969, 889,938 and 969,200 i-units to Enbridge Energy Management, L.L.C., the sole owner of our i-units, during 2008, 2007 and 2006, respectively, in lieu of cash distributions.

(2) We issued 1,615,601, 1,072,423 and 200,587 additional Class C units to our Class C unitholders in lieu of cash distributions during 2008, 2007, and 2006 including 529,207, 385,032 and 100,293 to our general partner, respectively.

(3) We retained an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner to maintain its 2 percent general partner interest in us.

12. 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 us. 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. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

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 to us by Enbridge and its affiliates.

Certain of the 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, number of full-time equivalent employees and capital employed.

During 2008, 2007 and 2006, we incurred the following costs related to these services, which are included in operating and administrative expenses.

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Direct workforce costs	$207.5	$181.6	$152.1
Allocated Liquids and Natural Gas operating costs	26.1	20.1	17.3
Allocated management and administrative costs, including insurance	36.2	28.9	27.4
	$269.8	$230.6	$196.8

Enbridge and its affiliates allocated direct workforce costs to us related to our construction projects of $13.2 million, $18.1 million and $11.8 million during 2008, 2007 and 2006, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

Affiliate Revenues 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. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the twelve months ending December 31, 2008, 2007 and 2006, are operating revenues of $267.0 million, $95.2 million, and $42.8 million, respectively, related to these transactions.

In 2007, we entered into an agreement with Enbridge Pipelines to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines. As compensation for installing and operating these transportation facilities, Enbridge Pipelines makes annual payments to us on a cost of service basis. The income we accrued for providing these transportation services in 2008 and 2007 was approximately $0.7 million and $0.6 million, respectively.

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, 2008, 2007 and 2006, are costs for natural gas purchases of $99.3 million, $6.2 million and $11.5 million, respectively, related to these purchases.

Notes Payable to Affiliates

Hungary Note Payable

As of December 31, 2008 and 2007, we had $130.0 million in amounts outstanding under notes payable to Enbridge Hungary Ltd., an affiliate of our general partner (the "Hungary Note"). The Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. The Hungary Note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. The Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes. For the years ended December 31, 2008 and 2007, we made interest payments of approximately $10.9 million and $8.8 million, respectively.

EUS Credit Agreement

In December 2007, we entered into an unsecured revolving credit agreement (the "EUS Credit Agreement") with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Credit Facility as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Credit Facility. At December 31, 2008, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use. The EUS Credit Agreement is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes.

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper projects where we are constructing the United States portion of the projects and Enbridge Pipelines is constructing the Canadian portion. In September 2008, we acquired for $21.1 million, approximately 22 miles of 36 inch diameter line pipe from our general partner for our use in constructing the Alberta Clipper project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access Extension. This transaction was approved by the Enbridge Management Board of Directors.

General Partner Equity Transactions

Our general partner owns an effective two percent general partner interest in us. Pursuant to our partnership agreement we paid cash distributions to our general partner of $43.7 million, $34.9 million, and $28.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. The cash distributions we make to our general partner exclude an amount equal to two percent of the i-unit and Class C unit distributions, which we retain from the General Partner to maintain its two percent general partner interest in us.

As of December 31, 2008, our general partner owned 16,250,000 Class A common units, representing a 13.9% limited partner interest in us. In December 2008, we issued and sold 16.25 million Class A common units to the General Partner in a private placement for a purchase price of $30.76 per unit, or approximately $500 million. The Class A common units represent limited partner ownership interests in the Partnership and increased the General Partner's ownership in the Partnership from approximately 15 percent to approximately 27 percent. The General Partner also contributed approximately $10.2 million to us to maintain its two percent general partner interest.

As of December 31, 2008 and 2007, our general partner also owned 3,912,750 Class B common units, representing a 3.4 and 4.2 percent limited partner interest in us for the respective years. We paid the General Partner cash distributions of $15.2 million, $14.5 million, and $14.5 million for the years ended December 31, 2008, 2007 and 2006, respectively, with respect to its ownership of Class B common units.

At December 31, 2008, 2007 and 2006, our general partner owned 6,449,315, 5,920,108 and 5,535,076 of our Class C units. We distributed 529,207, 385,032 and 100,293 additional Class C units to our general partner during the years ended December 31, 2008, 2007 and 2006, respectively, in lieu of making cash distributions. The Class C units owned by our general partner at December 31, 2008, 2007 and 2006 represent an approximately 5.5 percent, 6.4 percent and 7.0 percent limited partner interest in us. Refer to Note 11 for additional information regarding the Class C units.

The following table presents our public issuances of Class A common units and private placement of Class C units for the periods presented where our general partner did not participate but made a contribution to retain its two percent general partner interest.

Issuance Date	Class of Limited Partnership Interest	Number of units Issued	Offering Price per unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)				
March 2008	Class A	4,600,000	$49.000	$217.2	$4.6	$221.8
May 2007	Class A	5,300,000	58.000	301.9	6.1	308.0
April 2007	Class C	5,930,792	53.113	314.4	6.4	320.8

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

In August 2006, we sold approximately 5.4 million of our Class C units to our general partner for $250 million, or $46.00 per unit and 5.4 million Class C units to institutional investors for $250 million. As part of this transaction our general partner contributed approximately $10.2 million to maintain its two percent general partner interest.

Conflicts of Interest

Enbridge Management makes all decisions relating to the management of our business and affairs through a delegation of control agreement with our general partner and us. Our general partner owns the voting shares of Enbridge Management and elects all of its directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of our general partner. Some of our general partner's directors and officers 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 all 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 our 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 other 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.

13. COMMITMENTS AND CONTINGENCIES

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 hydrocarbon and natural 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 our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, our 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 November 2007, an unexpected release and fire on line 3 of our Lakehead system occurred during planned maintenance near our Clearbrook, Minnesota terminal. We immediately shut down all pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline at an economic cost of $4.1 million as of December 31, 2008. The volume of oil released was approximately 325 barrels, which was largely contained in the trench that had been excavated to facilitate the planned maintenance. We completed excavation and repairs and returned the line to service within five days of the incident. In October of 2008, we received a letter from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") alleging violations of federal pipeline safety regulations and proposing a $2.4 million fine related to the release and fire. A provision for the amount of the fine has been made in "Accounts payable and other." We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused this incident.

As of December 31, 2008 and 2007, we have recorded $5.5 million and $3.4 million, respectively, in "Accounts payable and other" and $2.8 in "Other long-term liabilities" for both years, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets, and penalties we have been or expect to be assessed.

Oil and Gas in Custody

Our liquids assets transport crude oil and NGLs owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline systems at any one time varies from approximately 22 to 40 million barrels, virtually all of which is owned by our customers. Under the terms of our tariffs, losses of crude oil from identifiable 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 NGLs in our custody.

Approximately 50 percent of the natural gas volumes on our natural gas assets are transported for customers on a contractual basis. We purchase the remaining 50 percent and sell to third-parties downstream of the purchase point. At any point in time, the value of our customers' natural gas in the custody of our natural gas systems is not material to us.

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 have recorded expenses of $2.0 million, $1.6 million, and $2.1 million for the leased right-of-way agreements for the years ended December 31, 2008, 2007, and 2006, 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 operating results, cash flows and financial position.

Future Minimum Commitments

As of December 31, 2008, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2009	2010	2011	2012	2013	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$299.3	$ —	$ —	$ —	$ —	$ —	$299.3
Power commitments[2]	2.1	—	—	—	—	—	2.1
Other operating leases	12.0	10.2	10.1	9.7	9.9	63.2	115.1
Right-of-way[3]	1.9	1.8	1.8	1.8	1.7	43.2	52.2
Product purchase obligations[4]	29.2	32.6	33.1	32.9	32.4	65.6	225.8
Service contract obligations[5]	27.8	22.9	20.7	10.2	1.5	—	83.1
Total	$372.3	$67.5	$65.7	$54.6	$45.5	$172.0	$777.6

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion projects.

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to approximate $1.7 million to $1.9 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2013.

(4) 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.

(5) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

The purchases made under our non-cancelable commitments for the years ended December 31, 2008, 2007 and 2006 were $389.9 million, $483.8 million and $171.4 million, respectively.

14. FAIR VALUES OF 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 credit facility borrowings approximate their fair values at December 31, 2008, due to the short-term nature of these obligations. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third party investment dealers who actively make markets in our debt securities, which are used to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

	December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$ —	$ —	$268.5	$268.5
Credit Facility	166.8	166.8	400.0	400.0
9.150% First Mortgage Notes	93.0	93.8	124.0	135.1
5.358% Senior unsecured zero coupon notes due 2022	214.7	211.0	203.6	210.7
4.000% Senior Notes due 2009	175.0	175.2	200.0	198.5
7.900% Senior Notes due 2012	99.9	93.7	99.9	110.2
4.750% Senior Notes due 2013	199.9	163.4	199.8	192.0
5.350% Senior Notes due 2014	199.9	151.3	199.9	194.3
5.875% Senior Notes due 2016	299.8	234.5	299.7	293.7
7.000% Senior Notes due 2018	99.9	81.9	99.9	105.3
6.500% Senior Notes due 2018	398.0	317.7	—	—
9.875% Senior Notes due 2019	499.7	500.4	—	—
7.125% Senior Notes due 2028	99.8	72.7	99.8	104.3
5.950% Senior Notes due 2033	199.7	119.7	199.7	176.9
6.300% Senior Notes due 2034	99.8	62.3	99.8	92.1
7.500% Senior Notes due 2038	398.9	289.2	—	—
8.050% Junior subordinated notes due 2067	399.3	209.3	399.3	385.9

Interest Rate Derivatives

We enter into interest rate swaps, collars and derivative financial instruments with similar characteristics to manage the effect of future interest rate movements on our interest costs. The following table provides information about our current interest rate derivatives by transaction type for the specified periods.

	Notional Principal	Partnership Pays	Partnership Receives	Maturity Date	Fair Value at December 31, 2008	Fair Value at December 31, 2007
	(dollars in millions)				(dollars in millions)	
Interest Rate Swaps						
Floating to Fixed:						
	$ 50.0	4.6175%	LIBOR[2]	January 15, 2009	$ —	$(0.3)
	$ 50.0	4.6130%	LIBOR	January 29, 2009	—	(0.3)
	$ 50.0	4.6525%	LIBOR	February 13, 2009	(0.1)	(0.4)
	$ 50.0	4.5875%	LIBOR	February 20, 2009	(0.2)	(0.4)
	$ 50.0	4.3700%	LIBOR-21 bps[1]	June 1, 2013	(5.3)	(0.7)
	$ 50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(5.2)	(0.6)
	$ 25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(2.7)	(0.3)
Fixed to Floating:						
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	6.1	1.6
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	6.1	1.6
	$ 25.0	LIBOR-25 bps	4.7500%	June 1, 2013	3.1	0.9
Treasury Locks:						
	$100.0	4.7500%	30Yr UST[3]	June 30, 2008	—	(4.4)
	$100.0	4.7140%	30Yr UST	June 30, 2008	—	(3.9)
Interest Rate Collars:						
Calls	$ 50.0	5.5000%	LIBOR	June 13, 2008	—	—
Puts	$ 50.0	4.1990%	LIBOR	June 13, 2008	—	—
Calls	$ 50.0	5.5000%	LIBOR	June 25, 2008	—	—
Puts	$ 50.0	4.1490%	LIBOR	June 25, 2008	—	—

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

(3) UST refers to United States Treasury notes.

Our short-term floating to fixed rate interest rate swaps, with the exception of the contract maturing February 13, 2009, qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on $150 million of our variable rate indebtedness. As such, the fair values of these derivative financial instruments are recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in “Accumulated other comprehensive income,” or AOCI. We discontinued hedge accounting treatment in December 2008 for our floating to fixed rate interest rate swap maturing February 13, 2009 originally hedging $50 million of our variable rate indebtedness when we reduced the balance of our Credit Facility below $200 million. As such, changes in the fair value of this derivative financial instrument are recorded in earnings as an increase or decrease in “Interest expense.”

The long-term floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 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, 2008 and 2007.

	December 31, 2008					December 31, 2007	
		Wtd. Average Price		Fair Value[3]		Fair Value[3]	
	Notional	Receive	Pay	Asset	Liability	Asset	Liability
				(dollars in millions)			
Swaps							
Natural gas[1]							
Receive variable/pay fixed	31,567,721	$ 5.59	$ 7.47	$ 8.4	$ (68.0)	$21.6	$ (16.1)
Receive fixed/pay variable	45,051,114	5.50	6.37	44.0	(81.0)	11.5	(160.5)
Receive variable/pay variable	210,887,678	6.04	6.08	9.7	(16.9)	11.5	(6.0)
NGL[2]							
Receive variable/pay fixed	259,095	27.57	61.48	—	(8.7)	—	—
Receive fixed/pay variable	6,288,742	49.56	29.04	126.7	(0.3)	—	(160.6)
Crude [2]							
Receive fixed/pay variable	1,390,000	77.15	64.54	18.8	(1.9)	—	(34.6)
Options-calls							
Natural gas[1]	1,095,000	4.31	6.84	—	(2.6)	—	(5.6)
Options-puts							
Natural gas[1]	359,587	5.79	9.22	—	(1.2)	—	—
NGL[2]	858,832	53.59	28.84	21.6	—	0.7	—
Totals[4]				$229.2	$(180.6)	$45.3	$(383.4)

(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) Fair values of derivatives are presented in millions of dollars.

(4) 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.

The following table sets forth by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	Fair Value at December 31, 2008			
Recurring fair value measures	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Derivative instruments, net	$ 20.4	$—	$119.6	$ 140.0
Liabilities:				
Derivative instruments, net	(77.5)	—	(27.8)	(105.3)
Total	$(57.1)	$—	$ 91.8	$ 34.7

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the year ended December 31, 2008. As reflected in the table, the net unrealized gains on Level 3 financial assets and liabilities was $149.7 million for the year ended December 31, 2008, which resulted from forward price decreases in natural gas, natural gas liquids, or NGLs, and crude oil derivative instruments that we held at December 31, 2008.

	Derivative Instruments, net
	(in millions)
Balance at January 1, 2008	$(167.7)
Realized and unrealized net gains	260.9
Purchases and settlements	(1.4)
Transfer in (out) of Level 3	—
Balance at December 31, 2008	$ 91.8
Change in unrealized net gains relating to instruments still held at December 31, 2008	$ 149.7

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 difference between the price we receive from NGL sales and the corresponding cost of 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 manage the risks associated with market fluctuations in commodity prices and interest rates, as well as reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with forecasted natural gas and NGL sales and purchases through 2013 in accordance with our risk management policies.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value which we adjust 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, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in Cost of natural gas for our commodity-based derivatives and Interest expense for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income (“AOCI”), a component of Partners’ Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. 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 hedges and qualify for hedge accounting are included in Cost of natural gas for commodity hedges and Interest expense for interest rate hedges in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued, remain in AOCI 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. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, 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 hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain or 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 or 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 on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge 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 four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included 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 the associated financial instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

2. **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.
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 cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. 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 being marked-to-market, 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.
4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

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 or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) 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.

We routinely enter into interest rate swaps to fix the interest rates associated with our variable rate debt, including commercial paper and bank borrowings. In August 2007, we entered into forward-starting interest rate swaps that we designated as cash flow hedges of variable rate debt to begin in October 2007 and November 2007. The specific floating rate borrowings did not take place as initially forecast, thereby causing the interest rates swaps to no longer qualify as cash flow hedges. As a result, we recorded a charge to interest expense of $1.4 million, representing the fair market value of the interest rate swaps at December 31, 2007. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of cost of natural gas and interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ (0.1)	$ —	$ (1.9)
Non-qualified hedges	85.1	(59.0)	1.8
Marketing			
Non-qualified hedges	(16.2)	(3.8)	64.5
Commodity derivative fair value gains (losses)	68.8	(62.8)	64.4
Corporate			
Non-qualified interest rate hedges	—	(1.4)	—
Derivative fair value gains (losses)	$ 68.8	$(64.2)	$64.4

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2008	2007
	(in millions)	
Other current assets	$ 70.6	$ 6.5
Other assets, net	75.7	6.4
Accounts payable and other	(40.6)	(165.5)
Other long-term liabilities	(71.0)	(192.9)
	$ 34.7	$(345.5)

The net assets associated with derivative activities are primarily due to the decrease in current and forward natural gas and NGL prices from December 31, 2007 to December 31, 2008. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $1.5 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2008, 2007 and 2006, we reclassified unrealized losses of $140.5 million, $94.8 million and $78.3 million, respectively, from AOCI to cost of natural gas on our consolidated statements of income for the fair value of derivative financial instruments that were settled.

In connection with our April 2008 issuances and sales of $400 million in principal amount of 6.50% senior notes due April 15, 2018 and $400 million in principal amount of 7.50% senior notes due April 15, 2038, we paid $22.1 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the senior notes maturing in 2038. The $22.1 million is being amortized from AOCI to "Interest expense" over the 30-year term of the senior notes.

As of December 31, 2008, we held $17.9 million of cash collateral which had been posted by our counterparties pursuant to the terms of our International Securities Dealers Association ("ISDA®") agreements. This collateral has been netted with outstanding exposure and is allocated to the asset accounts presented above.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2008	2007
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(39.6)	(298.3)
A	73.3	(47.2)
Lower than A	(1.2)	—
	32.5	(345.5)
Credit valuation adjustment	2.2	—
Total	$ 34.7	$(345.5)

* As determined by nationally recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to decreases in forward commodity prices, we continue to closely monitor our outstanding financial exposure. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

16. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose an income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. Beginning in 2006, two states (Michigan and Texas) enacted substantial changes to their tax structures to impose taxes that are based upon many but not all items included in net income. We report these taxes as income taxes under the provisions of SFAS No. 109.

Our income tax expense is $7.0 million and $5.1 million for the years ended December 31, 2008 and 2007, respectively, which we computed by applying a 0.50% Texas state income tax rate to modified gross margin and a 0.10% Michigan state income tax rate to modified gross revenue. Our income tax expense represents a 1.7% and 2.0% effective rate as applied to pretax book income for December 31, 2008 and 2007, respectively. At December 31, 2008 and 2007 we have included a current income tax payable of $5.2 million and $4.9 million in property and other taxes payable, respectively. In addition, at December 31, 2008, we have included a deferred income tax liability of $2.6 million in "Other long-term liabilities" and a deferred income tax asset at December 31, 2007 of $0.6 million in "Other assets, net" on our consolidated statement of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting. For the year ended December 31, 2008 and 2007, we paid $5.3 million and zero in income taxes, respectively. As of December 31, 2008, we have no liability reported for unrecognized tax benefits.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

	December 31, 2008	December 31, 2007
	(in millions)	
Net book basis of assets in excess of tax basis	$(2.1)	$(1.3)
Net book losses (income) on derivatives not recognized for tax purposes	(0.5)	1.9
Net deferred tax asset (liability)	$(2.6)	$ 0.6

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ending December 2007, 2006, and 2005.

17. 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 tables present certain financial information relating to our business segments:

	As of and for the year ended December 31, 2008				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 773.4	$7,828.0	$4,837.4	$ —	$13,438.8
Less: Intersegment revenue	0.3	3,150.9	227.6	—	3,378.8
Operating revenue	773.1	4,677.1	4,609.8	—	10,060.0
Cost of natural gas	—	3,982.4	4,590.5	—	8,572.9
Operating and administrative	189.4	328.5	10.1	7.1	535.1
Power	140.7	—	—	—	140.7
Depreciation and amortization	100.8	121.0	1.6	—	223.4
Operating income	342.2	245.2	7.6	(7.1)	587.9
Interest expense	—	—	—	180.6	180.6
Other income	—	—	—	2.9	2.9
Income before income tax expense	342.2	245.2	7.6	(184.8)	410.2
Income tax expense	—	—	—	7.0	7.0
Net income	$ 342.2	$ 245.2	$ 7.6	$(191.8)	$ 403.2
Total assets	$3,976.7	$3,580.2	$ 319.1	$ 424.9	$ 8,300.9
Capital expenditures (excluding acquisitions)	$1,054.1	$ 303.6	$ —	$ 17.7	$ 1,375.4

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the year ended December 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 548.1	$5,807.3	$3,527.5	$ —	$9,882.9
Less: Intersegment revenue	—	2,363.3	237.0	—	2,600.3
Operating revenue	548.1	3,444.0	3,290.5	—	7,282.6
Cost of natural gas	—	2,990.0	3,256.9	—	6,246.9
Operating and administrative	156.1	266.7	8.0	3.5	434.3
Power	117.0	—	—	—	117.0
Depreciation and amortization	67.9	96.1	1.6	—	165.6
Operating income	207.1	91.2	24.0	(3.5)	318.8
Interest expense	—	—	—	99.8	99.8
Other income	—	—	—	3.0	3.0
Income from continuing operations before income tax expense	207.1	91.2	24.0	(100.3)	222.0
Income tax expense	—	—	—	5.1	5.1
Income from continuing operations	207.1	91.2	24.0	(105.4)	216.9
Income from discontinued operations	—	32.6	—	—	32.6
Net income	$ 207.1	$ 123.8	$ 24.0	$(105.4)	$ 249.5
Total assets	$2,976.9	$3,461.1	$ 349.6	$ 104.0	$6,891.6
Capital expenditures (excluding acquisitions)	$1,218.8	$ 747.9	$ 1.6	$ 11.9	$1,980.2

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the year ended December 31, 2006				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 512.8	$5,404.1	$3,182.3	$ —	$9,099.2
Less: Intersegment revenue	—	2,383.4	206.8	—	2,590.2
Operating revenue	512.8	3,020.7	2,975.5	—	6,509.0
Cost of natural gas	—	2,601.1	2,913.5	—	5,514.6
Operating and administrative	141.3	215.4	5.4	2.7	364.8
Power	107.6	—	—	—	107.6
Depreciation and amortization	64.1	70.3	0.5	0.2	135.1
Operating income	199.8	133.9	56.1	(2.9)	386.9
Interest expense	—	—	—	110.5	110.5
Other income	—	—	—	8.5	8.5
Income before income tax expense	199.8	133.9	56.1	(104.9)	284.9
Income tax expense	—	—	—	—	—
Net income	$ 199.8	$ 133.9	$ 56.1	$(104.9)	$ 284.9
Total assets	$1,816.4	$2,797.3	$ 366.9	$ 243.2	$5,223.8
Capital expenditures (excluding acquisitions)	$ 237.2	$ 614.8	$ 1.9	$ 10.5	$ 864.4

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

18. SUBSEQUENT EVENTS

UTOS Disposition

In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), LLC, a wholly-owned subsidiary of Enbridge. 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 contracts. The UTOS system was not considered strategic to the ongoing operations of the Partnership, but is strategically aligned with Enbridge's offshore operations.

Distribution to Partners

On January 30, 2009, the board of directors of Enbridge Management declared a distribution payable to our partners on February 13, 2009. The distribution was paid to unitholders of record as of February 5, 2009, of our available cash of $128.0 million at December 31, 2008, or $0.990 per limited partner unit. Of this distribution, $93.2 million was paid in cash, $14.6 million was distributed in i-units to our i-unitholder, $19.5 million was distributed in Class C units to the holders of our Class C units and $0.7 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

Regulatory – North Dakota Tariff Filing

Effective January 1, 2009, we increased our rates for transportation on our North Dakota System to include an updated calculation of the two surcharges relating to the Phase V Expansion program. These surcharges are applicable for the five years immediately following the in-service date of the Phase V Expansion program, which was placed in service in January 2008. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originated at Trenton and Alexander, North Dakota. The rates and surcharges for transportation of light crude oil to principle delivery points via trunk lines on the Enbridge North Dakota System are set forth below:

	Indexed Base Rate per Barrel	Phase V Surcharge Per Barrel	Published Rate per Barrel FERC No. 59(1)
From Glenburn, Haas, Lignite, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$0.8120	$0.1758	$0.9878
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	0.9298	0.1758	1.1056
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to Clearbrook, Minnesota	0.9558	0.1758	1.1316
From Tioga, North Dakota to Clearbrook, Minnesota	0.8379	0.1758	1.0137
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	1.0609	0.8714	1.9323
From Alexander, North Dakota to Clearbrook, Minnesota	1.1000	0.8714	1.9714
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5108	—	0.5108
From Reserve, Montana to Tioga, North Dakota	0.5762	—	0.5762
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	0.4847	0.6956	1.1803
From Alexander, North Dakota to Clearbrook, Minnesota	0.5235	0.6956	1.2191

(1) Pursuant to FERC Tariff No. 59 as filed with the FERC on December 1, 2008, with an effective date of January 1, 2009.

19. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for our "Adjustments to reconcile net income to net cash provided: Other" balance in our consolidated statement of cash flows.

	For the year ended December 31,		
	2008	2007	2006
		(in millions)	
Discount accretion	$11.5	$ 3.8	$ 0.3
Environmental liabilities	5.9	(2.0)	(1.4)
Amortization of debt issuance and hedging costs	7.4	—	5.3
Deferred income taxes	1.3	0.2	0.8
Other	(0.6)	(0.2)	2.8
	$25.5	$ 1.8	$ 7.8

20. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
		(in millions, except per unit amounts)			
2008 Quarters					
Operating revenue	$2,435.3	$2,932.2	$2,812.7	$1,879.8	$10,060.0
Operating income	$ 132.3	$ 109.5	$ 171.7	$ 174.4	$ 587.9
Net income	$ 103.1	$ 58.8	$ 119.4	$ 121.9	$ 403.2
Net income per limited partner unit[1]	$ 0.99	$ 0.50	$ 1.09	$ 1.04	$ 3.63
2007 Quarters					
Operating revenue	$1,712.7	$1,738.7	$1,710.9	$2,120.3	$ 7,282.6
Operating income	$ 64.1	$ 90.9	$ 101.6	$ 62.2	$ 318.8
Income from continuing operations	$ 39.1	$ 68.6	$ 77.3	$ 31.9	$ 216.9
Income from discontinued operations	$ —	$ —	$ —	$ 32.6	$ 32.6
Net income	$ 39.1	$ 68.6	$ 77.3	$ 64.5	$ 249.5
Net income per limited partner unit[1]	$ 0.40	$ 0.69	$ 0.75	$ 0.59	$ 2.45

[1] The General Partner's allocation of net income has been deducted before calculating net income per limited partner unit.