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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended: December 31, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-32678

DCP MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**03-0567133** *(I.R.S. Employer Identification No.)*
370 17th Street, Suite 2775 **Denver, Colorado** *(Address of principal executive offices)*	**80202** *(Zip Code)*

Registrant's telephone number, including area code: 303-633-2900

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

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Units Representing Limited Partner Interests	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 Exchange Act of 1934, or the Act. Yes o 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 o 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 Act 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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. o

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. (Check one):

Large accelerated filer o	Accelerated filer ☑	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant on June 30, 2007, was approximately $617,513,000. The aggregate market value was computed by reference to the last sale price of the registrant's common units on the New York Stock Exchange on June 29, 2007.

As of March 3, 2008, there were outstanding 20,411,754 common limited partner units and 3,571,429 subordinated units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

DCP MIDSTREAM PARTNERS, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2007

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GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

Bbls	barrels
Bbls/d	barrels per day
BBtu/d	one billion Btus per day
Bcf/d	one billion cubic feet per day
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
Frac spread	price differences, measured in energy units, between equivalent amounts of natural gas and NGLs
MBbls	one thousand barrels
MBbls/d	one thousand barrels per day
MMBtu	one million Btus
MMBtu/d	one million Btus per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGLs	natural gas liquids
Tcf	one trillion cubic feet
Throughput	the volume of product transported or passing through a pipeline or other facility

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" as well as the following risks and uncertainties:

- the level and success of natural gas drilling around our assets, and our ability to connect supplies to our gathering and processing systems in light of competition;
- our ability to grow through acquisitions, contributions from affiliates, or organic growth projects, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets, which will depend on general market conditions, interest rates and our ability to effectively limit a portion of the adverse effects of potential changes in interest rates by entering into derivative financial instruments, and the credit ratings for our debt obligations;
- the extent of changes in commodity prices, our ability to effectively limit a portion of the adverse impact of potential changes in prices through derivative financial instruments, and the potential impact of price on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- our ability to purchase propane from our principal suppliers for our wholesale propane logistics business;
- our ability to construct facilities in a timely fashion, which is partially dependent on obtaining required building, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for supplies;
- the creditworthiness of counterparties to our transactions;
- weather and other natural phenomena, including their potential impact on demand for the commodities we sell and our and third-party-owned infrastructure;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the increased regulation of our industry;
- industry changes, including the impact of consolidations, increased delivery of liquefied natural gas to the United States, alternative energy sources, technological advances and changes in competition;
- the amount of collateral we may be required to post from time to time in our transactions; and
- general economic, market and business conditions.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described.

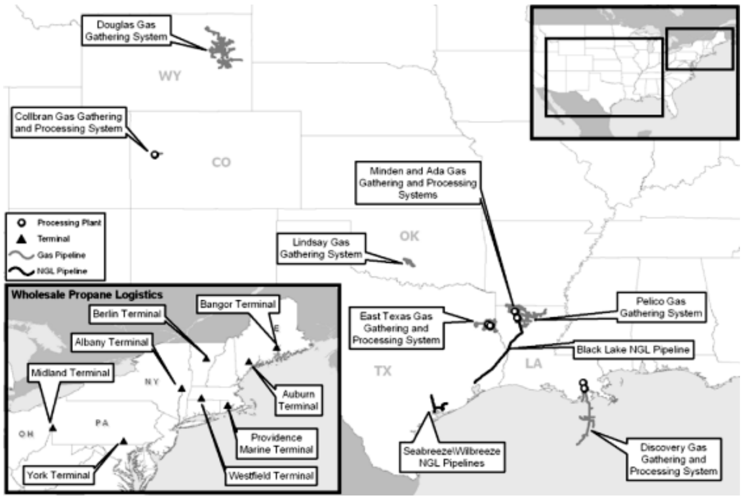
We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Item 1. ***Business***

Our Partnership

DCP Midstream Partners, LP along with its consolidated subsidiaries, or we, us, our, or the partnership, is a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are currently engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas, producing, transporting, storing and selling propane in wholesale markets and transporting and selling NGLs and condensate. Supported by our relationship with DCP Midstream, LLC and its parents, Spectra Energy Corp, or Spectra Energy, and ConocoPhillips, we have a management team dedicated to executing our growth strategy by acquiring and constructing additional assets.

Our operations are organized into three business segments, Natural Gas Services, Wholesale Propane Logistics and NGL Logistics. A map representing the location of the assets that comprise our segments is set forth below. Additional maps detailing the individual assets can be found on our website at *www.dcppartners.com*.



Our Natural Gas Services segment includes:

- our Northern Louisiana system is an integrated pipeline system located in northern Louisiana and southern Arkansas that gathers, compresses, treats, processes, transports and sells natural gas, and that transports and sells NGLs and condensate. This system consists of the following:
  - the Minden processing plant and gathering system, which includes a 115 MMcf/d cryogenic natural gas processing plant supplied by approximately 725 miles of natural gas gathering pipelines, connected to approximately 460 receipt points, with throughput and processing capacity of approximately 115 MMcf/d;

- the Ada processing plant and gathering system, which includes a 45 MMcf/d refrigeration natural gas processing plant supplied by approximately 130 miles of natural gas gathering pipelines, connected to approximately 210 receipt points, with throughput capacity of approximately 80 MMcf/d; and
- the Pelico Pipeline, LLC system, or Pelico system, an approximately 600-mile intrastate natural gas gathering and transportation pipeline with throughput capacity of approximately 250 MMcf/d and connections to the Minden and Ada processing plants and approximately 450 other receipt points. The Pelico system delivers natural gas to multiple interstate and intrastate pipelines, as well as directly to industrial and utility end-use markets.

- our Southern Oklahoma, or Lindsay, gathering system, that was acquired in May 2007, consists of approximately 225 miles of pipeline, with throughput capacity of approximately 35 MMcf/d;
- our equity interests that were acquired in July 2007 from DCP Midstream, LLC, consist of the following:
  - our 40% interest in Discovery Producer Services LLC, or Discovery, which operates a 600 MMcf/d cryogenic natural gas processing plant, a natural gas liquids fractionator plant, an approximately 280-mile natural gas pipeline with approximate throughput capacity of 600 MMcf/d that transports gas from the Gulf of Mexico to its processing plant, and several onshore laterals expanding its presence in the Gulf; and
  - our 25% interest in DCP East Texas Holdings, LLC, or East Texas, which operates a 780 MMcf/d natural gas processing complex, a natural gas liquids fractionator and an 845-mile gathering system with approximate throughput capacity of 780 MMcf/d, as well as third party gathering systems, and delivers residue gas to interstate and intrastate pipelines; and
- our Colorado and Wyoming gathering, processing and compression assets were acquired in August 2007 from DCP Midstream, LLC, and consist of the following:
  - our 70% operating interest in the approximately 30-mile Collbran Valley Gas Gathering system, or Collbran system, has assets in the Piceance Basin that gather and process natural gas from over 20,000 dedicated acres in western Colorado, and a processing facility with a capacity that is being expanded from an original capacity of 60 MMcf/d to 120 MMcf/d; and
  - The Powder River Basin assets, which include the approximately 1,320-mile Douglas gas gathering system, or Douglas system, with throughput capacity of approximately 60 MMcf/d and covers more than 4,000 square miles in northeastern Wyoming, and Millis terminal, and associated NGL pipelines in southwestern Wyoming.

Our Wholesale Propane Logistics segment acquired in November 2006 from DCP Midstream, LLC includes:

- six owned rail terminals located in the Midwest and northeastern United States, one of which is currently idle, with aggregate storage capacity of 25 MBbls;
- one leased marine terminal located in Providence, Rhode Island, with storage capacity of 410 MBbls;
- one pipeline terminal located in Midland, Pennsylvania with storage capacity of 56 MBbls; and
- access to several open access pipeline terminals.

Our NGL Logistics segment includes:

- our Seabreeze pipeline, an approximately 68-mile intrastate NGL pipeline located in Texas with throughput capacity of 33 MBbls/d;
- our Wilbreeze pipeline, the construction of which was completed in December 2006, an approximately 39-mile intrastate NGL pipeline located in Texas, which connects a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, with throughput capacity of 11 MBbls/d; and

- our 45% interest in the Black Lake Pipe Line Company, or Black Lake, the owner of an approximately 317-mile interstate NGL pipeline in Louisiana and Texas with throughput capacity of 40 MBbls/d.

For additional information on our segments, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and Note 17 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Our Business Strategies

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following business strategies:

Optimize: maximize the profitability of existing assets. We intend to optimize the profitability of our existing assets by maintaining existing volumes and adding volumes to enhance utilization, improving operating efficiencies and capturing marketing opportunities when available. Our natural gas and NGL pipelines have excess capacity, which allows us to connect new supplies of natural gas and NGLs at minimal incremental cost. Our wholesale propane logistics business has diversified supply options that allow us to capture lower cost supply to lock in our margin, while providing reliable supplies to our customers.

Build: capitalize on organic expansion opportunities. We continually evaluate economically attractive organic expansion opportunities to construct new midstream systems in new or existing operating areas. For example, we believe there are opportunities to expand several of our gas gathering systems to attach increased volumes of natural gas produced in the areas of our operations. We also believe that we can continue to expand our wholesale propane logistics business via the construction of new propane terminals.

Acquire: pursue strategic and accretive acquisitions. We plan to pursue strategic and accretive acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation. We believe there will continue to be acquisition opportunities as energy companies continue to divest their midstream assets. We intend to pursue acquisition opportunities both independently and jointly with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips, and we may also acquire assets directly from them, which we believe will provide us with a broader array of growth opportunities than those available to many of our competitors.

Our Competitive Strengths

We believe that we are well positioned to execute our business strategies and achieve our primary business objective of increasing our cash distribution per unit because of the following competitive strengths:

Affiliation with DCP Midstream, LLC and its parents. Our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips, should continue to provide us with significant business opportunities. DCP Midstream, LLC is one of the largest gatherers of natural gas (based on wellhead volume), one of the largest producers of NGLs and one of the largest marketers of NGLs in North America. This relationship also provides us with access to a significant pool of management talent. We believe our strong relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies. Additionally, we believe DCP Midstream, LLC, which operates many of our assets on our behalf, has established a reputation in the midstream business as a reliable and cost-effective supplier of services to our customers, and has a track record of safe, efficient and environmentally responsible operation of our facilities.

Strategically located assets. Our assets are strategically located in areas that hold potential for expanding each of our business segments’ volume throughput and cash flow generation. Our Natural Gas Services segment has a strategic presence in several active natural gas producing areas including Northern Louisiana, eastern Texas, western Colorado, northeastern Wyoming, southern Oklahoma, and the Gulf of Mexico. These natural gas gathering systems provide a variety of services to our customers including natural gas gathering, compression, treating, processing, fractionation and transportation services. The strategic location of our assets, coupled with their geographic diversity, presents us continuing opportunities to provide competitive natural gas services to our customers and opportunities to attract new natural gas production. Our NGL Logistics segment has strategically located NGL transportation pipelines in northern Louisiana, eastern Texas and southern Texas, all of which are major NGL producing regions. Our NGL pipelines connect to various natural gas processing plants in the region and transport the NGLs to large fractionation facilities, a petrochemical plant or an underground NGL storage facility along the Gulf Coast. Our Wholesale Propane Logistics Segment has terminals in the Northeastern and upper Midwestern states that are strategically located to receive and deliver propane to one of the largest demand areas for propane in the United States.

Stable cash flows. Our operations consist of a favorable mix of fee-based and margin-based services, which together with our derivative activities, generate relatively stable cash flows. While our percentage-of-proceeds gathering and processing contracts subject us to commodity price risk, we have mitigated a portion of our currently anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas and crude oil swaps. For additional information regarding our derivative activities, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Commodity Cash Flow Protection Activities.”

Integrated package of midstream services. We provide an integrated package of services to natural gas producers, including gathering, compressing, treating, processing, transporting and selling natural gas, as well as transporting and selling NGLs. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all services that producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.

Comprehensive propane logistics systems. We have multiple propane supply sources and terminal locations for wholesale propane delivery. We believe our ability to purchase large volumes of propane supply and transport such supply for resale or storage allows us to provide our customers with reliable supplies of propane during periods of tight supply. These capabilities also allow us to moderate the effects of commodity price volatility and reduce significant fluctuations in our sales volumes.

Experienced management team. Our senior management team and board of directors includes some of the most senior officers of DCP Midstream, LLC and former senior officers from other energy companies who have extensive experience in the midstream industry. Our management team has a proven track record of enhancing value through the acquisition, optimization and integration of midstream assets.

Our Relationship with DCP Midstream, LLC and its Parents

One of our principal strengths is our relationship with DCP Midstream, LLC and its parents, Spectra Energy and ConocoPhillips. DCP Midstream, LLC intends to use us as an important growth vehicle to pursue the acquisition, expansion, and existing and organic construction of midstream natural gas, NGL and other complementary energy businesses and assets. In November 2006, we acquired our wholesale propane logistics business, in July 2007, we acquired our interests in Discovery and East Texas, and in August 2007, we acquired our Collbran and Douglas systems associated with Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC. We expect to have future opportunities to make additional acquisitions directly from DCP Midstream, LLC; however, we cannot say with any certainty which, if any, of these acquisitions may be made available to us, or if we will choose to pursue any such opportunity. In addition, through our relationship with DCP Midstream, LLC and its parents, we expect to have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and DCP Midstream, LLC’s broad operational, commercial, technical, risk management and administrative infrastructure.

DCP Midstream, LLC has a significant interest in our partnership through its general partner interest in us, all of our incentive distribution rights and a 33.9% limited partner interest in us. We have entered into an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC and some of its affiliates that governs our relationship with them regarding the operation of many of our assets, as well as certain reimbursement and indemnification matters.

Natural Gas and NGLs Overview

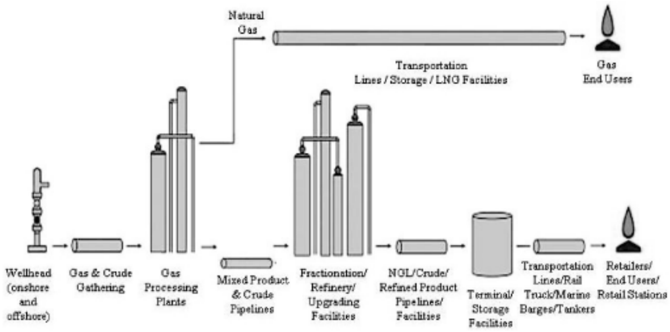
The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets, and consists of the gathering, compression, treating, processing, transportation and selling of natural gas, and the production, transportation and selling of NGLs.

Natural Gas Demand and Production

Natural gas is a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to increase from approximately 22.3 Tcf in 2006 to approximately 23.9 Tcf in 2010, representing an average annual growth rate of over 1.8% per year. The industrial and electricity generation sectors are the largest users of natural gas in the United States, accounting for approximately 59% of the total natural gas consumed in the United States during 2006. Driven by projections of continued growth in natural gas demand and higher natural gas prices, domestic natural gas production is projected to increase from 19.0 Tcf per year to 19.9 Tcf per year between 2006 and 2010.

Midstream Natural Gas Industry

Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. The following diagram illustrates the natural gas gathering, processing, fractionation, storage and transportation process, which ultimately results in natural gas and its components being delivered to end-users.



Natural Gas Gathering

The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once the well is completed, the well is connected to a gathering system. Onshore gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Natural Gas Compression

Gathering systems are generally operated at design pressures that will maximize the total throughput from all connected wells. Since wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production from the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of wellhead gas is compressed to a desired higher pressure, allowing gas to flow into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to lower the pressure of a gathering system to operate at a lower pressure or provide sufficient pressure to deliver gas into a higher pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural Gas Processing and Transportation

The principal component of natural gas is methane, but most natural gas also contains varying amounts of NGLs including ethane, propane, normal butane, isobutane and natural gasoline. NGLs have economic value and are utilized as a feedstock in the petrochemical and oil refining industries or directly as heating, engine or industrial fuels. Long-haul natural gas pipelines have specifications as to the maximum NGL content of the gas to be shipped. In order to meet quality standards for long-haul pipeline transportation, natural gas collected through a gathering system may need to be processed to separate hydrocarbon liquids that can have higher values as mixed NGLs from the natural gas. NGLs are typically recovered by cooling the natural gas until the mixed NGLs become separated through condensation. Cryogenic recovery methods are processes where this is accomplished at temperatures lower than minus 150°F. These methods provide higher NGL recovery yields. After being extracted from natural gas, the mixed NGLs are typically transported via NGL pipelines or trucks to a fractionator for separation of the NGLs into their component parts.

In addition to NGLs, natural gas collected through a gathering system may also contain impurities, such as water, sulfur compounds, nitrogen or helium. As a result, a natural gas processing plant will typically provide ancillary services such as dehydration and condensate separation prior to processing. Dehydration removes water from the natural gas stream, which can form ice when combined with natural gas and cause corrosion when combined with carbon dioxide or hydrogen sulfide. Condensate separation involves the removal of hydrocarbons from the natural gas stream. Once the condensate has been removed, it may be stabilized for transportation away from the processing plant via truck, rail or pipeline. Natural gas with a carbon dioxide or hydrogen sulfide content higher than permitted by pipeline quality standards requires treatment with chemicals called amines at a separate treatment plant prior to processing.

Wholesale Propane Logistics Overview

General

We are engaged in wholesale propane logistics in the Midwest and northeastern United States. Wholesale propane logistics covers the receipt of propane from processing plants, fractionation facilities and crude oil refineries, the transportation of that propane by pipeline, rail or ship to terminals and storage facilities, the storage of propane during low-demand seasons and the delivery of propane to retail distributors.

Production of Propane

Propane is extracted from natural gas at processing plants, separated from raw mixed NGLs at fractionation facilities or separated from crude oil during the refining process. Most of the propane that is consumed in the United States is produced at processing plants, fractionation facilities and refineries located in the mid-continent, along the Texas and Louisiana Gulf Coast or in foreign locations, particularly Canada, the North Sea, East Africa and the Middle East. There are limited processing plants and fractionation facilities in the northeastern United States, and propane production is limited.

Transportation

While significant refinery production exists, propane delivery ratios are limited and refineries sometimes use propane as internal fuel during winter months. As a result, the northeastern United States is an importer of propane, relying almost exclusively on pipeline, marine and rail sources for incoming supplies.

Storage

Independent terminal operators and wholesale distributors, such as us, own, lease or have access to propane storage terminals that receive supplies via pipeline, ship or rail. Generally, inventories in the propane storage facilities increase during the spring and summer months for delivery to customers during the fall and winter heating season when demand is typically at its peak.

Delivery

Often, upon receipt of propane at marine, rail and pipeline terminals, product is delivered to customer trucks or is stored in tanks located at the terminals or in off-site bulk storage facilities for future delivery to customers. Most terminals and storage facilities have a tanker truck loading facility commonly referred to as a "rack." Often independent retailers will rely on independent trucking companies to pick up product at the rack and transport it to the retailer at its location. Each truck has transport capacity of generally between 9,500 and 12,500 gallons of propane.

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of a geographically diverse complement of assets and ownership interests that provide a varying array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, fractionating and transporting natural gas; however, we do not offer all services in every location. These assets are positioned in areas with active drilling programs and opportunities for both organic growth and readily integrated acquisitions. We operate in six states in the continental United States including Arkansas, Colorado, Louisiana, Oklahoma, Texas and Wyoming. The assets in these states include our Northern Louisiana system, our Southern Oklahoma system, our equity interests in Discovery and East Texas, our 70% operating interest in the Collbran system and our Douglas system. The Southern Oklahoma and East Texas assets provide operating synergies and opportunities for growth in conjunction with DCP Midstream. This geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas producing area. We believe our current geographic mix of assets will be an important factor for maintaining overall volumes and cash flow for this segment.

Our Natural Gas Services segment consists of approximately 4,200 miles of pipe, five processing plants, two NGL fractionation facilities and over 120,000 horsepower of compression capability. The processing plants that service our natural gas gathering systems include two company owned cryogenic facilities with approximately 115 MMcf/d of processing capacity, one company owned refrigeration style facility with approximately 145 MMcf/d of processing capacity and two cryogenic facilities owned via equity interests with our proportionate share at approximately 435 MMcf/d of processing capacity. Further, our Minden and Discovery processing facilities both have ethane rejection capabilities that serve to optimize value of the gas stream. The combined NGL production from our processing facilities is in excess of 22,000 barrels per day and is delivered and sold into various NGL takeaway pipelines or trucked out.

The volume throughput on our assets is in excess of 750 MMcf/d from over 4,000 individual receipt points and originates from a diversified mix of natural gas producing companies. Our Southern Oklahoma, East Texas, Northern Louisiana, Discovery and Collbran systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint.

We have primarily a mix of percentage-of-proceeds and fee-based contracts with our producing customers in our Natural Gas Services segment. Contracts at Minden, Southern Oklahoma, Douglas, Discovery and East Texas have a large component of percentage-of-proceeds contracts due to the processing component of the gas streams at each of these systems. In addition, Discovery may also generate a portion of its earnings through keep-whole contracts. The Pelico, Ada and Collbran systems are predominantly supported by fee-based contracts. This diverse contract mix is a result of contracting patterns that are largely a result of the competitive landscape in each particular geographic area.

In total, our natural gas gathering systems have the ability to deliver gas into over 20 downstream transportation pipelines and markets. Many of our outlets transport gas to premium markets in the eastern United States, further enhancing the competitiveness of our commercial efforts in and around our natural gas gathering systems.

Gathering Systems, Processing Plants and Transportation Systems

Following is operating data for our systems:

System	Approximate Gas Gathering and Transmission System (Miles)	Partnership Operated Plants	Plants Operated by Others	Fractionator Operated by Others	Approximate Net Plant Capacity (MMcf/d)	2007 Operating Data Natural Gas Throughput (MMcf/d)(a)	NGL Production (Bbls/d)(a)
Minden	725	1	—	—	115	84	5,175
Ada	130	1	—	—	45	65	171
Pelico	600	—	—	—	—	214	—
Southern Oklahoma (Lindsay)	225	—	—	—	—	12	1,491
Collbran	30	1	—	—	100	24	107
Douglas	1,320	—	—	—	—	7	695
Discovery	280	—	1	1	240(b)	212(b)	6,580(b)
East Texas	845	—	1	1	195(b)	138(b)	7,903(b)
Total	4,155	3	2	2	695	756	22,122

(a) Represents total volumes for 2007 divided by 365 days.

(b) For Discovery and East Texas, includes our 40% and 25% proportionate share, respectively, of the approximate net plant capacity, natural gas throughput and NGL production.

The Northern Louisiana natural gas gathering system includes the Minden, Ada and Pelico systems, which gather natural gas from producers at approximately 670 receipt points and deliver it for processing to the processing plants. The Minden gathering system also delivers NGLs produced at the Minden processing plant to our 45%-owned Black Lake pipeline. There are 26 compressor stations located within the system, comprised of 60 units with an aggregate of approximately 70,000 horsepower. Through our Northern Louisiana system, we offer producers and customers wellhead-to-market services. The Northern Louisiana system has numerous market outlets for the natural gas we gather, including several intrastate and interstate pipelines, major industrial end-users and major power plants. The system is strategically located to facilitate the transportation of natural gas from Texas and northern Louisiana to pipeline connections linking to markets in the eastern and northeastern areas of the United States.

The Minden processing plant is a cryogenic natural gas processing and treating plant located in Webster Parish, Louisiana. This processing plant has amine treating and ethane recovery and rejection capabilities such that we can recover approximately 80% of the ethane contained in the natural gas stream. In addition, the processing plant is able to reject ethane of effectively 13% when justified by market economics.

The Ada gathering system is located in Bienville and Webster parishes in Louisiana and the Ada processing plant is a refrigeration natural gas processing plant located in Bienville Parish, Louisiana. This low pressure gathering system compresses and processes natural gas for our producing customers and delivers residue gas into our Pelico intrastate system. We then sell the NGLs to third-parties who truck them from the plant tailgate.

The Pelico system is an intrastate natural gas gathering and transportation pipeline that gathers and transports natural gas that does not require processing from producers in the area at approximately 450 meter locations. Additionally, the Pelico system transports processed gas from the Minden and Ada processing plants and natural gas supplied from third party interstate and intrastate natural gas pipelines. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana.

The Southern Oklahoma system consists of 9,500 horsepower of compression, and 352 receipt points, and is located in the Golden Trend area of McClain, Garvin and Grady counties in southern Oklahoma. The system was acquired from Anadarko Petroleum Corporation in May 2007 and is adjacent to assets owned by DCP Midstream, LLC. Currently, natural gas gathered by the system is delivered to the Oneok Maysville plant for processing; however, we will have the ability in 2009 to process the gas at a DCP Midstream, LLC processing plant to enhance our processing economics. The current Maysville connection provides marketing flexibility to multiple pipelines and access to local liquid markets using Oneok's fractionation capabilities.

The Collbran system has assets in the southern Piceance Basin that gather natural gas at high pressure from over 20,000 dedicated acres in western Colorado, and a refrigeration natural gas processing plant with a current capacity of 100 MMcf/d. Our 70% operating interest in the Collbran system was acquired from DCP Midstream, LLC in August 2007 following its acquisition of MEG. The remaining interests in the joint venture are held by Plains Exploration & Production Company (25%) and Delta Petroleum Corporation (5%), who are also producers on the system. The processing plant is currently under expansion to increase its operating capacity to 120 MMcf/d during the first half of 2008 to accommodate expected increases in volumes for 2008.

The Douglas system has natural gas gathering pipelines that cover more than 4,000 square miles in Wyoming with over 1,300 miles of pipe. The system gathers primarily rich casing-head gas from oil wells at low pressure from approximately 1,000 receipt points and delivers the gas to a third party for processing under a fee agreement. We employ over 16,000 horsepower of compression on this system to maintain our low pressure gathering service. The Douglas system was acquired from DCP Midstream, LLC in August 2007 following its acquisition of MEG.

We have a 40% equity interest in Discovery (the remaining 60% is owned by Williams Partners, L.P.), which in turn owns (1) a natural gas gathering and transportation pipeline system located primarily off the coast of Louisiana in the Gulf of Mexico, with six delivery points connected to major interstate and intrastate pipeline systems; (2) a cryogenic natural gas processing plant in Larose, Louisiana; (3) a fractionator in Paradis, Louisiana and (4) a mixed NGL pipeline connecting the gas processing plant to the fractionator. The Discovery system, operated by the Williams Companies, offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Lafourche Parish, Louisiana.

Discovery is managed by a two-member management committee, consisting of one representative from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in Discovery. All actions and decisions relating to Discovery require the unanimous approval of the owners except for a few limited situations. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval based on the ownership percentage represented, will determine the amount of the distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an "area of interest."

Additionally, Discovery has signed definitive agreements with Chevron Corporation, Royal Dutch Shell plc, and StatoilHydro ASA to construct an approximate 35-mile gathering pipeline lateral to connect Discovery's existing pipeline system to these producers' production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion is expected to have a design capacity of approximately 200 MMcf/d. In October 2007, Chevron announced that it will face delays because of metallurgical problems discovered in the facility's mooring shackles and that it does not expect first production to commence until the third quarter of 2009. In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for remaining costs for the Tahiti pipeline lateral expansion.

We own a 25% interest in East Texas (the remaining 75% is owned by DCP Midstream, LLC), which gathers, transports, treats, compresses and processes natural gas and NGLs. The East Texas facility may also fractionate NGL production, which can be marketed at nearby petrochemical facilities. The operations, located near Carthage, Texas, include a natural gas processing complex that is connected to its gathering system, as well as third party gathering systems. The complex includes the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub acts as a key exchange point for the purchase and sale of residue gas in the eastern Texas region. The East Texas system consists 845 miles of pipe, processing capacity of 780 MMcf/d, fractionation capacity of 11,000 Bbls/d, over 25,000 horsepower of compression and serves over 1,500 receipt points in and around its geographic footprint.

East Texas is managed by a four-member management committee, consisting of two representatives from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in East Texas. Most significant actions relating to East Texas require the unanimous approval of both owners. East Texas must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions.

Natural Gas Markets

The Northern Louisiana system has numerous market outlets for the natural gas that we gather on the system. Our natural gas pipelines connect to the Perryville Market Hub, a natural gas marketing hub that provides connection to four intrastate or interstate pipelines, including pipelines owned by Southern Natural Gas Company, Texas Gas Transmission, LLC, CenterPoint Energy Mississippi River Transmission Corporation and CenterPoint Energy Gas Transmission Company. In addition, our natural gas pipelines in northern Louisiana also have access to gas that flows through pipelines owned by Texas Eastern Transmission, LP, Crosstex LIG, LLC, Gulf South Pipeline Company, Tennessee Natural Gas Company and Regency Intrastate Gas, LLC. The Northern Louisiana system is also connected to eight major industrial end-users and makes deliveries to three power plants.

The NGLs extracted from the natural gas at the Minden processing plant are delivered to our 45%-owned Black Lake pipeline through our wholly-owned approximately 9-mile Minden NGL pipeline. The NGLs extracted from natural gas at the Ada processing plant are sold at market index prices to affiliates and are delivered to third parties’ trucks at the tailgate of the plant.

The Southern Oklahoma system has access through the Maysville processing plant to deliver gas into mid-continent transmission pipelines such as Oneok Gas Transportation and Southern Star Central Gas Pipelines, among others. When the Southern Oklahoma system delivers into the DCP Midstream, LLC owned processing plant(s) in the second quarter of 2009, a similar mix of mid-continent pipelines and markets will be available to our customers.

The Collbran system in western Colorado delivers gas into the TransColorado Gas Transmission interstate pipeline and to the Rocky Mountain Natural Gas LDC. The Douglas system in the Powder River basin in northeastern Wyoming delivers to the Kinder Morgan Interstate Gas Transmission interstate pipeline. The NGLs from the Collbran system are trucked off site by third party purchasers, while NGLs on the Douglas system are transported on the ConocoPhillips owned Powder River Pipeline.

The Discovery assets have access to downstream pipelines and markets including Texas Eastern Transmission Company, Bridgeline, Gulf South Pipeline Company, Transcontinental Gas Pipeline Company, Columbia Gulf Transmission and Tennessee Gas Pipeline Company, among others. The NGLs are fractionated at the Paradis fractionation facilities and delivered downstream to third-party purchasers. The third party purchasers of the fractionated NGLs consist of a mix of local petrochemical facilities and wholesale distribution companies for the ethane and propane components, while the butanes and natural gasoline are delivered and sold to pipelines that transport product to the storage and distribution center near Napoleonville, Louisiana or other similar product hub.

The East Texas system delivers gas primarily to the Carthage Hub which delivers residue gas to ten different interstate and intrastate pipelines including Centerpoint Energy Gas Transmission, Texas Gas

Transmission, Tennessee Gas Pipeline Company, Natural Gas Pipeline Company of America, Gulf South Pipeline Company, Enterprise and others. Certain of the lighter NGLs, consisting of ethane and propane, are fractionated at the East Texas facility and sold to regional petrochemical purchasers. The remaining NGLs, including butanes and natural gasoline, are purchased by DCP Midstream, LLC and shipped on the Panola NGL pipeline to Mont Belvieu for fractionation and sale.

Customers and Contracts

The primary suppliers of natural gas to our Natural Gas Services segment are a broad cross-section of the natural gas producing community. We actively seek new producing customers of natural gas on all of our systems to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been released from other gathering systems.

We had no third-party customers in our Natural Gas Services segment that accounted for greater than 10% of our revenues.

Our contracts with our producing customers in our Natural Gas Services segment are primarily a mix of commodity sensitive percentage-of-proceeds contracts and non-commodity sensitive fee-based contracts. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. The largest percentage of volumes at Minden, Southern Oklahoma, Douglas and East Texas are processed under percentage-of-proceeds contracts. Discovery has percentage-of-proceeds contracts and fee-based contracts, as well as some keep-whole contracts. The majority of the contracts for our Pelico, Ada and Collbran systems are fee-based agreements. Our gross margin generated from percentage-of-proceeds contracts is directly correlated to the price of natural gas, NGLs and condensate. To minimize potential future commodity-based pricing volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes associated with our gathering and processing operations through 2013.

Discovery's wholly owned subsidiary, Discovery Gas Transmission, owns the mainline and the Federal Energy Regulatory Commission, or FERC-regulated laterals, which generate revenues through a tariff on file with the FERC for several types of service: traditional firm transportation service with reservation fees (although no current shippers have elected this service); firm transportation service on a commodity basis with reserve dedication; and interruptible transportation service. In addition, for any of these general services, Discovery Gas Transmission has the authority to negotiate a specific rate arrangement with an individual shipper and has several of these arrangements currently in effect.

Competition

Competition in our Natural Gas Services segment is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

Wholesale Propane Logistics Segment

General

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We own assets and do business in the states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Ohio, Pennsylvania, Rhode Island and Vermont.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We believe these factors generally allow us to maintain favorable relationships with our customers.

These factors have allowed us to remain a supplier to many of the large retail distributors in the northeastern United States. As a result, we serve as the baseload provider of propane supply to many of our retail propane distribution customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. The financial derivatives are accounted for using mark-to-market accounting. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may, on occasion, use financial derivatives to manage the value of our propane inventories.

Pipeline deliveries to the northeast market in the winter season are generally at capacity and competing pipeline dependent terminals can have supply constraints or outages during peak market conditions. Our system of terminals has substantial excess capacity, which provides us with opportunities to increase our volumes with minimal additional cost. Additionally, we constructed a propane pipeline terminal located in Midland, Pennsylvania that became operational in May 2007, and we are actively seeking new terminals through acquisition or construction to expand our distribution capabilities.

Our Terminals

Our operations include six propane rail terminals with aggregate storage capacity of 25 MBbls, one of which is currently idle, one propane marine terminal with storage capacity of 410 MBbls, one propane pipeline terminal with storage capacity of 56 MBbls and access to several open access pipeline terminals. We own our rail terminals and lease the land on which the terminals are situated under long-term leases. Our marine terminal is leased a long-term lease agreement. Each of our rail terminals consist of two to four propane tanks with capacity of between 30,000 and 90,000 gallons for storage, and two high volume loading racks for loading propane into trucks. Our aggregate truck-loading capacity is approximately 400 trucks per day. We could expand each of our terminals' loading capacity by adding a third loading rack to handle future growth. High volume submersible pumps are utilized to enable trucks to fully load within 15 minutes. Each facility also has the ability to unload multiple railcars simultaneously. We have numerous railcar leases that allow us to increase our storage and throughput capacity as propane demand increases. Each terminal relies on leased rail trackage for the storage of the majority of its propane inventory in these leased railcars. These railcars mitigate the need for larger numbers of fixed storage tanks and reduce initial capital needs when constructing a terminal. Each railcar holds approximately 30,000 gallons of propane.

We are also actively seeking to expand and favorably position our wholesale propane distribution business into the upper Midwest and Mid-Atlantic states, and have constructed a propane pipeline terminal in western Pennsylvania that became operational in May 2007.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under annual and multi-year agreements under index-based pricing. The remaining supply is purchased on annual or month-to-month terms to match our anticipated sale requirements. During 2007 and 2006, our primary suppliers of propane included Aux Sable Liquid Products LP and Shell International Trading and Shipping Company, and during 2007, our primary suppliers also included a subsidiary of DCP Midstream, LLC.

For our rail terminals, we contract for propane at various major supply points in the United States and Canada, and transport the product to our terminals under long-term rail commitments, which provide fixed transportation costs that are subject to prevailing fuel surcharges. We also purchase propane supply from natural gas fractionation plants and crude oil refineries located in the Texas and Louisiana Gulf Coast. Through this process, we take custody of the propane and either sell it in the wholesale market or store it at our facilities. For our marine terminal, we have historically contracted under annual agreements for delivered shipments of propane. In February 2008, one of our three primary propane suppliers terminated its supply contract with us. We are actively seeking alternative sources of supply and believe such supply sources are available on commercially acceptable terms. The port where our marine terminal facility is located has been expanded, and we can now receive propane supply from larger propane tankers.

Customers and Contracts

We typically sell propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with DCP Midstream, LLC or third parties that generally match the quantities of propane subject to these fixed price sales agreements. Our ability to help our clients manage their commodity price exposure by offering propane at a fixed price may lead to a larger customer base. Historically, approximately 75% of the gross margin generated by our wholesale propane business is earned in the heating season months of October through April, which corresponds to the general market demand for propane.

We had no third-party customers in our Wholesale Propane Logistics segment that accounted for greater than 10% of our revenues.

Competition

The wholesale propane business is highly competitive in the upper Midwest and northeastern regions of the United States. Our wholesale propane business' competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines.

NGL Logistics Segment

General

Our NGL transportation assets consist of our wholly-owned approximately 68-mile Seabreeze intrastate NGL pipeline and our wholly-owned approximately 39-mile Wilbreeze intrastate NGL pipeline, both of which are located in Texas, and a 45% interest in the approximately 317-mile Black Lake interstate NGL pipeline located in Louisiana and Texas. These NGL pipelines transport mixed NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and an underground NGL storage facility. In aggregate, our NGL transportation business has 73 MBbls/d of capacity and in 2007 average throughput was approximately 29 MBbls/d.

In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source. Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, when higher natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

NGL Pipelines

Seabreeze and Wilbreeze Pipelines. The Seabreeze pipeline has capacity of 33 MBbls/d and for 2007 average throughput on the pipeline was approximately 17 MBbls/d. The Seabreeze pipeline was put into service in 2002 to deliver an NGL mix to a large processing plant with processing capacity of approximately 340 MMcf/d located in Matagorda County, Texas, a large processing plant with capacity of approximately 250 MMcf/d located in Matagorda County, Texas, and an NGL pipeline. The Seabreeze pipeline is the sole NGL pipeline for the two processing plants and is the only delivery point for the NGL pipeline. This third party NGL pipeline transports NGLs from five natural gas processing plants located in southeastern Texas that have aggregate processing capacity of approximately 1.6 Bcf/d. Three of these processing plants are owned by DCP Midstream, LLC. The seven processing plants that produce NGLs that flow into the Seabreeze pipeline process natural gas produced in southern Texas and offshore in the Gulf of Mexico. The Seabreeze pipeline delivers the NGLs it receives from these sources to a fractionator and a storage facility. We completed construction of our Wilbreeze pipeline in December 2006. Current capacity of the Wilbreeze pipeline is 11 MBbls/d and average throughput on the pipeline was approximately 5 MBbls/d for 2007.

Black Lake Pipeline. The Black Lake pipeline has capacity of 40 MBbls/d and for 2007, average throughput on the Black Lake pipeline at our 45% interest was approximately 7 MBbls/d. The Black Lake pipeline was constructed in 1967 and delivers NGLs from processing plants in northern Louisiana and southeastern Texas to fractionation plants at Mont Belvieu on the Texas Gulf Coast. The Black Lake pipeline receives NGL mix from three natural gas processing plants in northern Louisiana, including our Minden plant, Regency Intrastate Gas, LLC's Dubach processing plant and Chesapeake Energy Corporation's Black Lake processing plant. The Black Lake pipeline is the sole NGL pipeline for all of these natural gas processing plants in northern Louisiana, as well as the Ceritas South Raywood processing plant located in southeastern Texas, and also receives NGL mix from XTO Energy Inc.'s Cotton Valley processing plant. In addition, the Black Lake pipeline receives NGL mix from a natural gas processing plant located in southeastern Texas.

There are currently five significant active shippers on the pipeline, with DCP Midstream, LLC historically being the largest, representing approximately 49% of total throughput in 2007. The Black Lake pipeline generates revenues through a FERC-regulated tariff, and the average rate per barrel was $0.95 in 2007, $0.94 in 2006 and $0.91 in 2005.

Black Lake is a partnership that is operated by and 50% owned by BP PLC. Black Lake is required by its partnership agreement to make monthly cash distributions equal to 100% of its available cash for each month, which is defined generally as receipts plus reductions in cash reserves less disbursements and increases in cash reserves. In anticipation of a pipeline integrity project, Black Lake suspended making monthly cash distributions in December 2004 in order to reserve cash to pay the expenses of this project. We expect that this project will be completed and cash distributions will resume in 2008.

Customers and Contracts

The Wilbreeze pipeline is supported by an NGL product dedication agreement with DCP Midstream, LLC.

Effective December 1, 2005, we entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will purchase the NGLs that were historically purchased by us, and DCP Midstream, LLC will pay us to transport the NGLs pursuant to a fee-based rate that will be applied to the volumes transported. We have entered into this fee-based contractual arrangement with the objective of generating approximately the same operating income per barrel transported that we realized when we were the purchaser and seller of NGLs. We do not take title to the products transported on the NGL pipelines; rather, the shipper retains title and the associated commodity price risk. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a long-term transportation agreement. The Seabreeze pipeline only collects fee-based transportation revenue under this agreement. DCP Midstream, LLC receives its supply of NGLs that it then transports on the Seabreeze pipeline under an NGL purchase agreement with Williams and an NGL purchase agreement with Enterprise Products Partners. Under these agreements, Williams and Enterprise Products Partners have each dedicated all of their respective NGL production from these processing plants to DCP Midstream, LLC. DCP Midstream, LLC has a sales agreement with Formosa. Additionally, DCP Midstream, LLC has a transportation agreement with TEPPCO Partners, L.P. that covers all of the NGL volumes transported on TEPPCO Partners, L.P.'s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

We had no third-party customers in our NGL Logistics segment that accounted for greater than 10% of our revenues.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of approximately $1.8 million between 2008 and 2011 to implement integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from December 2005 through June 2008 and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred during 2006. Reimbursements related to the Seabreeze pipeline integrity repairs in 2006 were not significant.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by FERC, under the Natural Gas Act of 1938, or NGA. Natural gas companies may not charge rates that have been determined not 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.

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. FERC-regulated natural gas 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.

In November 2003, the FERC issued Order 2004 governing the Standards of Conduct for Transmission Providers (including natural gas interstate pipelines). These standards provide that interstate pipeline employees engaged in natural gas transmission system operations must function independently from any employees of their energy affiliates and marketing affiliates and that an interstate pipeline must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially, an energy or marketing affiliate. In addition, Order 2004 restricts access to natural gas transmission customer data by marketing and other energy affiliates and provides certain conditions on service provided by interstate pipelines to their gas marketing and energy affiliates. In November 2006, the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit, vacated Order 2004 as that order applies to interstate natural gas pipelines and remanded that proceeding to the FERC for further action.

On January 9, 2007, the FERC issued Order 690 in response to the D.C. Circuit's decision. In its Order, the Commission issued new interim standards of conduct pending the outcome of a new rulemaking proceeding. The interim standards only govern the relationship between an interstate pipeline and its marketing affiliates as opposed to its energy affiliates, the latter being a much broader category as originally set forth in Order 2004. As a result, the Commission effectively "repromulgated" on a temporary basis the Standards of Conduct first issued in Order 497 in 1992, while it considers its course of action to address the court's decision on a more permanent basis.

On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking ("NOPR") in Docket No. RM07-1 wherein it proposes to make permanent its interim standards of conduct issued in Order 690. The Commission also sought comment as to whether it should make comparable changes to the electric industry standards of conduct that were not affected by either the November 2006 decision by the D.C. Circuit, or by Order 690, as well as comments regarding certain other electric-related exceptions to Order 2004. We continue to closely monitor these proceedings and administer our compliance programs accordingly.

The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the outer continental shelf, or OCS, provide open access, non-discriminatory transportation service. In an effort to heighten its oversight of transportation on the OCS, the FERC attempted to promulgate reporting requirements with respect to OCS transportation, but the regulations were struck down as ultra vires by a federal district court, which decision was affirmed by the D.C. Circuit in October 2003. The FERC withdrew those regulations in March 2004. Subsequently, in April 2004, the Minerals Management Service, or MMS, initiated an inquiry into whether it should amend its regulations to assure that pipelines provide open and non-discriminatory access over OCS pipeline facilities. In April 2007, the MMS issued a notice of proposed rulemaking that would establish a process for a shipper transporting oil or gas production from OCS leases to follow if it believes it has been denied open and nondiscriminatory access to OCS pipelines. However, the proposed rule makes clear that the MMS will defer to FERC with respect to pipelines subject to FERC's NGA and Interstate Commerce Act jurisdiction, stating that the MMS would not consider complaints regarding a FERC pipeline that, for example, originates from a lease on the OCS and then transports production onshore to an adjacent state. The MMS has also proposed a regulation providing for civil penalties of up to $10,000 per day for violations of the OCSLA's open and nondiscriminatory access requirements. The MMS has not yet issued a final rule. We have no way of knowing what rules the MMS will ultimately adopt regarding access to OCS transportation and what effect, if any, those rules will have on our OCS operations and related revenues and profitability.

On July 19, 2007, FERC issued a proposed policy statement regarding the appropriate composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. FERC proposed to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline's earnings and that evidence be provided in the form of a multiyear analysis of past earnings demonstrating a publicly traded partnership's ability to provide stable earnings over time. On November 15, 2007, the FERC requested additional comments regarding the method to be used for creating growth forecasts for publicly traded partnerships, and FERC held a technical conference on this issue in January 2008. The ultimate outcome of this proceeding is not certain and may result in new policies being established at FERC that would disallow the full use of distributions to unitholders by pipeline publicly traded partnerships in any proxy group comparisons used to determine return on equity in future rate proceedings.

On September 20, 2007, FERC issued a Notice of Inquiry regarding Fuel Retention Practices of Natural Gas Pipelines (Fuel NOI). The Fuel NOI inquires whether the current policy which allows natural gas pipelines to choose between two options for recovering the costs of fuel and lost and unaccounted for (LAUF) gas should be changed in favor of a uniform method. Comments have been filed in response to the Fuel NOI. The outcome of this proceeding could result in changes to the methodology used for calculating fuel and LAUF gas, which could potentially affect the Discovery's revenues.

On September 20, 2007, FERC issued a Notice of Proposed Rulemaking regarding Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines (Reporting NOPR). The Reporting NOPR proposed to require pipelines to (i) provide additional information regarding their sources of revenue and amounts included in rate base; (ii) identify costs related to affiliate transactions; and (iii) provide additional information regarding incremental facilities, and discounted and negotiated rates. According to FERC, the changes would assist pipeline customers and other third parties in analyzing a pipeline's actual return as compared with its approved rate of return based on publicly filed data. Although FERC proposed that the changes would be effective January 1, 2008, FERC has not yet issued a final rule. FERC's proposed rulemaking is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

On November 15, 2007, FERC issued a notice of proposed rulemaking proposing to permit market-based pricing for short-term capacity releases and to facilitate asset management arrangements by relaxing FERC's prohibition on tying and on its bidding requirements for certain capacity releases (Capacity Release NOPR). FERC proposes to lift the price ceiling for short-term capacity release transactions of one year or less. The Capacity Release NOPR is proposed to enable releasing shippers to offer competitively-priced alternatives to pipelines' negotiated rates and to encourage more efficient construction of capacity. Under FERC's proposal, it is possible for the releasing shipper to release the natural gas at market-based prices while pipelines would still be subject to the maximum rate cap. FERC's proposed rulemaking is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

On December 21, 2007, 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. Comments are due on March 13, 2008, and a technical conference will be held regarding these issues on April 3, 2008. Adoption of this proposal by FERC could result in additional administrative burdens and could result in increased capital costs.

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 are 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 FERC 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.

The Discovery interstate natural gas pipeline system filed with FERC on November 16, 2007 a settlement with a January 1, 2008 effective date. Also, modifications were made to the imbalance resolution and fuel reimbursement sections of Discovery's tariff. The settlement was approved on February 5, 2008 for all parties except ExxonMobil who contested the settlement. ExxonMobil will continue to pay the previous rates. ExxonMobil has an interruptible contract that was last used in 2006 so there will be no material impact by this outcome.

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. However, to the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. Under Section 311, intrastate pipelines providing interstate service may avoid jurisdiction that would otherwise apply under the NGA. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by the FERC at least once every three years. The rate review may, but does not necessarily, involve an administrative-type hearing before the FERC staff panel and an administrative appellate review. Additionally, the terms and conditions of service set forth in the intrastate pipeline's Statement of Operating Conditions are subject to FERC approval. Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties. Among other matters, EPAct 2005 amends the NGPA to give FERC authority to impose civil penalties for violations of the NGPA up to $1,000,000 per day per violation for violations occurring after August 8, 2005. For violations occurring before August 8, 2005, FERC had the authority to impose civil penalties for violations of the NGPA up to $5,000 per violation per day. The Pelico and EasTrans systems are subject to FERC jurisdiction under Section 311 of the NGPA.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that our natural gas pipelines meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

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. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC’s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Propane Regulation

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

Interstate NGL Pipeline Regulation

The Black Lake pipeline is an interstate NGL pipeline subject to FERC regulation. The FERC regulates interstate NGL pipelines under its Oil Pipeline Regulations, the Interstate Commerce Act, or ICA, and the Elkins Act. FERC requires that interstate NGL pipelines file tariffs containing all the rates, charges and other terms for services performed. The ICA requires that tariffs apply to the interstate movement of NGLs, as is the case with the Black Lake pipeline. Pursuant to the ICA, rates can be challenged at FERC either by protest when they are initially filed or increased or by complaint at any time they remain on file with FERC.

In October 1992, Congress passed the Energy Policy Act of 1992, or EPAct, which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods, PPI-FG, plus 1.3% to the new ceiling level. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the PPI-FG falls and 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 unless doing so would reduce a rate "grandfathered" by EPAct (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The FERC's indexing methodology is subject to review every five years; the current methodology is expected to remain in place through June 30, 2011. If the FERC continues its policy of using the PPI-FG plus 1.3%, changes in that index might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, thus hampering our ability to recover cost increases.

EPAct deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the ICA. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the petroleum pipeline, or in the nature of the services provided, that were a basis for the rate. EPAct places no such limit on challenges to a provision of a petroleum pipeline tariff as unduly discriminatory or preferential.

In May 2007, the D.C. Circuit upheld a determination by FERC that a rate is no longer subject to grandfathering protection under EPAct when there has been a substantial change in the overall rate of return of the pipeline, rather than in one cost element. Further, the D.C. Circuit declined to consider arguments that there were errors in the FERC's method for determining substantial change, finding that the parties had not first raised such allegations with FERC. On August 20, 2007, the D.C. Circuit denied a petition for rehearing of the May 29 decision with respect to the alleged errors in the FERC's method for determining substantial change and the decision is now final. In December of 2007, the FERC issued two orders that provided further clarification of the standard to be used for determining whether there has been substantial change sufficient to remove grandfathering protection.

The pending FERC proceeding regarding the appropriate composition of proxy groups for purposes of determining equity returns to be included in cost-of-service based rates is also applicable to FERC-regulated oil pipelines. The ultimate outcome of the FERC's proxy group proceeding is currently not certain.

Intrastate NGL Pipeline Regulation

Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, transporting, processing or storing natural gas, propane, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the acquisition of permits to conduct regulated activities;
- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. For instance, we or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third party suppliers. Third parties also assist us in interpreting the results of the inspections. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

DCP Midstream, LLC has agreed to indemnify us in an aggregate amount not to exceed $15.0 million until December 7, 2008 for environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before the closing date of our initial public offering on December 7, 2005. We have not sought indemnification from DCP Midstream, LLC as of March 3, 2008.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion of the more significant environmental laws and regulations that relate to our business and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Air Emissions

Our operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. Following the performance of an audit by us during 2007 on facilities included in our Northern Louisiana system, we identified and subsequently self-disclosed to the Louisiana Department of Environmental Quality alleged violations of environmental law arising primarily from historical operations at certain of those facilities. We are currently involved in settlement discussions with the Louisiana Department of Environmental Quality to resolve these alleged matters. Aside from this enforcement matter we believe that we are in material compliance with these requirements, and that our future operations will not be materially adversely affected by such requirements.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances or solid wastes, including petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict, joint and several liability for the investigation and remediation of areas at a facility where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Despite the “petroleum exclusion” of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle “hazardous substances” within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA’s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as “hazardous wastes” and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could reasonably have a material impact on our operations or financial condition.

Water

The Federal Water Pollution Control Act of 1972, as amended, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water run-off. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water run-off. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Global Warming and Climate Change

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases often referred to as "greenhouse gases" may be contributing to warming of the Earth's atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act, or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a "cap and trade" scheme of regulation of greenhouse gas emissions — a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. Debate and a possible vote on this bill by the full Senate are anticipated to occur before mid-year 2008. In addition, at least one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations (*e.g.*, compressor units) or from combustion of fuels (*e.g.*, oil or natural gas) we process. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, or Massachusetts, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Court's holding in the *Massachusetts* decision that greenhouse gases including carbon dioxide fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain CAA programs. New federal or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the oil and gas we transport.

Anti-Terrorism Measures

The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, known as the Chemical Facility Anti-Terrorism Standards interim rule, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to the interim rules that established chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Facilities possessing greater than threshold levels of these chemicals of interest were required to prepare and submit to the DHS in January 2008 initial screening surveys that the agency would use to determine whether the facilities presented a high level of security risk. Covered facilities that are determined by DHS to pose a high level of security risk will be notified by DHS and will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. We have not yet determined the extent to which our facilities are subject to the interim rules or the associated costs to comply, but it is possible that such costs could be material.

Employees

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, or the General Partner, which is wholly-owned by DCP Midstream, LLC. As of December 31, 2007, the General Partner or its affiliates employed nine people directly and approximately 146 people who provided direct support for our operations through DCP Midstream, LLC. None of these employees are covered by collective bargaining agreements. Our General Partner considers its employee relations to be good.

General

We make certain filings with the Securities and Exchange Commission, or SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports, which are available free of charge through our website, *www.dcppartners.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at *www.sec.gov*. Our annual reports to unitholders, press releases and recent analyst presentations are also available on our website.

Item 1A. ***Risk Factors***

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this annual report in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to continue to make cash distributions to holders of our common units and subordinated units at our current distribution rate.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, level of production of, and demand for, natural gas, propane, condensate and NGLs;
- the success of our commodity derivative and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- the volume of natural gas we gather, treat, compress, process, transport and sell, the volume of propane and NGLs we transport and sell, and the volumes of propane we store;
- the relationship between natural gas, NGL and crude oil prices;
- the level of competition from other midstream energy companies;
- the impact of weather conditions on the demand for natural gas and propane;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost and form of payment for acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash distributions we receive from our equity interests; and
- the amount of cash reserves established by our general partner.

We have partial ownership interests in a number of joint venture legal entities, including Discovery, East Texas and Black Lake, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to you.

Our inability, or limited ability, to control the operations and management of joint venture legal entities that we have a partial ownership interest in may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for entities where we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- We have limited ability to influence decisions with respect to the operations of these entities and their subsidiaries, including decisions with respect to incurrence of expenses and distributions to us;

- These entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;
- These entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- These entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these things could significantly and adversely impact our ability to distribute cash to the unitholders.

The amount of cash we have available for distribution to holders of our common units and subordinated units depends primarily on our cash flow and not solely on profitability.

Profitability may be significantly affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets include the level of successful drilling activity near these systems, and our ability to compete for volumes from successful new wells.

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. Currently, natural gas prices are high in relation to historical prices. For example, the rolling twelve-month average New York Mercantile Exchange, or NYMEX, daily settlement price of natural gas futures contracts has increased from $5.39 per MMBtu as of December 31, 2003 to $7.96 per MMBtu as of December 31, 2007. If the price of natural gas were to decline, the level of drilling activity could decrease. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and pipeline transportation systems and our natural gas treating and processing plants. Other factors that impact production decisions include producers' capital budgets, the ability of producers to obtain necessary drilling and other governmental permits, access to drilling rigs and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves.

The cash flow from our Natural Gas Services segment is affected by natural gas, NGL and condensate prices.

Our Natural Gas Services segment is affected by the level of natural gas, NGL and condensate prices. NGL and condensate prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. The markets and prices for natural gas, NGLs, condensate and crude oil depend upon factors beyond our control. These factors include supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, or extreme weather that may disrupt our operations;

- the level of domestic and offshore production;
- the availability of imported natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percentage-of-proceeds arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and NGLs resulting from our processing activities, and then sell the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuate. We have mitigated a portion of our share of anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations.

Our derivative activities may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate our cash flow exposure to fluctuations in the price of NGLs, we have primarily entered into derivative financial instruments relating to the future price of crude oil. If the price relationship between NGLs and crude oil changes, our commodity price risk may increase. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the open portion. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

We have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk relating to the equity volumes from our gathering and processing operations through 2013 by entering into derivative financial instruments relating to the future price of natural gas and crude oil. Additionally, we have entered into interest rate swap agreements to convert a portion of the variable rate revolving debt under our Credit Agreement to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. The intent of these arrangements is to reduce the volatility in our cash flows resulting from fluctuations in commodity prices and interest rates.

We will continue to evaluate whether to enter into any new derivative arrangements, but there can be no assurance that we will enter into any new derivative arrangement or that our future derivative arrangements will be on terms similar to our existing derivative arrangements. Although we enter into derivative instruments to mitigate our commodity price and interest rate risk, we also forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. As of March 3, 2008, we posted collateral with certain counterparties of approximately $47.9 million. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our derivative activities, these activities can result in material losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable derivative arrangement, the derivative arrangement is imperfect or ineffective, or our risk management policies and procedures are not properly followed or do not work as planned.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We are using the mark-to-market method of accounting for all commodity derivative instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity.

Volumes of natural gas dedicated to our systems in the future may be less than we anticipate.

As a result of the unwillingness of producers to provide reserve information as well as the cost of such evaluation, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our systems in the future could be less than we anticipate.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.

We identify as primary natural gas suppliers those suppliers individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas represented approximately 57% of the natural gas supplied in our Natural Gas Services segment during the year ended December 31, 2007. In our NGL Logistics segment, our largest NGL supplier is DCP Midstream, LLC, who obtains NGLs from various third party producer customers. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business.

If we are not able to purchase propane from our principal suppliers, or we are unable to secure transportation under our transportation arrangements, our results of operations in our wholesale propane logistics business would be adversely affected.

Most of our propane purchases are made under supply contracts that have a term of between one to five years and provide various pricing formulas. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane represented approximately 94% of our propane supplied during the year ended December 31, 2007. In February 2008, one of our three primary propane suppliers terminated its supply contract with us. We are actively seeking alternative sources of supply and believe such supply sources are available on commercially acceptable terms. In the event that we are unable to purchase propane from our significant suppliers or replace terminated supply contracts, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would hurt our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations. In addition, if we are unable to transport propane supply to our terminals under our rail commitments, our ability to satisfy customer demand and our revenue and results of operation would be adversely affected.

We may not be able to grow or effectively manage our growth.

A principal focus of our strategy is to continue to grow the per unit distribution on our units by expanding our business. Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- identify businesses engaged in managing, operating or owning pipelines, processing and storage assets or other midstream assets for acquisitions, joint ventures and construction projects;
- consummate accretive acquisitions or joint ventures and complete construction projects;
- appropriately identify any liabilities associated with any acquired businesses or assets;
- integrate any acquired or constructed businesses or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations.

A deficiency in any of these factors could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from acquisitions, joint ventures or construction projects. In addition, competition from other buyers could reduce our acquisition opportunities. In addition, DCP Midstream, LLC and its affiliates are not restricted from competing with us. DCP Midstream, LLC and its affiliates may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Furthermore, we have recently grown significantly through a number of acquisitions. For example, in May 2007 we acquired the Southern Oklahoma system, in July 2007 we acquired a 25% interest in East Texas and a 40% interest in Discovery from DCP Midstream, LLC and in August 2007 we acquired certain subsidiaries of MEG that hold our Douglas and Collbran assets from DCP Midstream, LLC. If we fail to properly integrate these acquired assets successfully with our existing operations, if the future performance of these acquired assets does not meet our expectations, or we did not identify a significant liability associated with the acquired assets, the anticipated benefits from these acquisitions may not be fully realized.

We may not successfully balance our purchases and sales of natural gas and propane.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. In addition, in our wholesale propane logistics business, we purchase propane from a variety of sources and resell the propane to retail distributors. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

Our NGL pipelines could be adversely affected by any decrease in NGL prices relative to the price of natural gas.

The profitability of our NGL pipelines is dependent on the level of production of NGLs from processing plants. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost (principally that of natural gas as a feedstock and fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, which would reduce the volumes and gross margins attributable to our NGL pipelines.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport or produce natural gas and NGLs.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control.

Service at our propane terminals may be interrupted.

Historically, a substantial portion of the propane we purchase to support our wholesale propane logistics business is delivered at our rail terminals or by ship at our leased marine terminal in Providence, Rhode Island. We also rely on shipments of propane via the Buckeye Pipeline for our Midland Terminal and via TEPPCO Partners, LP's pipeline to open access terminals. Any significant interruption in the service at these terminals would adversely affect our ability to obtain propane, which could reduce the amount of propane that we distribute, our revenues or cash available for distribution.

We operate in a highly competitive business environment.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas, propane and NGLs than we do. Some of these competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services we provide to our customers. Likewise, our customers who produce NGLs may develop their own systems to transport NGLs. Additionally, our wholesale propane distribution customers may develop their own sources of propane supply. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers.

Weather conditions, such as warm winters, principally in the northeastern United States, may affect the overall demand for propane.

Weather conditions could have an impact on the demand for wholesale propane because the end-users of propane depend on propane principally for heating purposes. As a result, warm weather conditions could adversely impact the demand for and prices of propane. Since our wholesale propane logistics business is located almost solely in the northeast, warmer than normal temperatures in the northeast can decrease the total volume of propane we sell. Such conditions may also cause downward pressure on the price of propane, which could result in a lower of cost or market adjustment to the value of our inventory.

Competition from alternative energy sources, conservation efforts and energy efficiency and technological advances may reduce the demand for propane.

Competition from alternative energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities. In addition, propane competes with heating oil primarily in residential applications. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and availability of natural gas in the northeast, which has historically depended upon propane, could reduce the demand for propane, which could adversely affect the volumes of propane that we distribute. In addition, stricter conservation measures in the future or technological advances in heating, energy generation or other devices could reduce the demand for propane.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on our Pelico pipeline system and the EasTrans Limited Partnership (EasTrans) pipeline system owned by East Texas, are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The Pelico system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under a rate settlement with FERC. The EasTrans system is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under an order approved by the Railroad Commission of Texas. The Black Lake pipeline system is an interstate transporter of NGLs and is subject to FERC jurisdiction under the Interstate Commerce Act and the Elkins Act.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPAct 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1,000,000 per day for each violation.

Other state and local regulations also affect our business. Our non-proprietary gathering lines are subject to ratable take and common purchaser statutes in Louisiana. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our proprietary gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

Discovery's interstate tariff rates are subject to review and possible adjustment by federal regulators. Moreover, because Discovery is a non-corporate entity, it may be disadvantaged in calculating its cost-of-service for rate-making purposes.

The FERC, pursuant to the NGA, regulates many aspects of Discovery's interstate pipeline transportation service, including the rates that Discovery is permitted to charge for such service. Under the NGA, interstate transportation rates must be just and reasonable and not unduly discriminatory. If the FERC fails to permit tariff rate increases requested by Discovery, or if the FERC lowers the tariff rates Discovery is permitted to charge its customers, on its own initiative, or as a result of challenges raised by Discovery's customers or third parties, Discovery's tariff rates may be insufficient to recover the full cost of providing interstate transportation service. In certain circumstances, the FERC also has the power to order refunds.

The Discovery interstate natural gas pipeline system filed with FERC on November 16, 2007 a settlement with a January 1, 2008 effective date. Also, modifications were made to the imbalance resolution and fuel reimbursement sections of Discovery's tariff. FERC approved the settlement on February 5, 2008 for all parties except ExxonMobil who contested the settlement. ExxonMobil will continue to pay the previous rates.

Under current policy, the FERC permits pipelines to include, in the cost-of-service used as the basis for calculating the pipeline's regulated rates, a tax allowance reflecting the actual or potential income tax liability on public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In a future rate case, Discovery may be required to demonstrate the extent to which inclusion of an income tax allowance in Discovery's cost-of-service is permitted under the current income tax allowance policy.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPAct 2005 FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions; (2) the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the discharge of waste from our facilities; and (3) the Comprehensive Environmental Response Compensation and Liability Act of 1980, or CERCLA, also known as "Superfund," and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas, NGLs and other petroleum products, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could 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 governmental claims for natural resource damages or fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance or from indemnification from DCP Midstream, LLC.

We may incur significant costs and liabilities resulting from implementing and administering pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in “high consequence areas.” The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipeline. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. Our NGL pipelines are also subject to integrity management and other safety regulations imposed by the TRRC.

We currently estimate that we will incur costs of approximately $1.8 million between 2008 and 2011 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be material. While DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with certain repair costs relating to the Black Lake pipeline resulting from the testing program that was implemented prior to our acquisition of this asset from DCP Midstream, LLC in December 2005 through June 2008, and for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred during 2006, the actual costs of making such repairs, including any lost cash flows resulting from shutting down the pipeline during the pendency of such repairs, could substantially exceed the amount of such indemnity.

We currently transport all of the NGLs produced at our Minden plant on the Black Lake pipeline. Accordingly, in the event that the Black Lake pipeline becomes inoperable due to any necessary repairs resulting from our integrity testing program or for any other reason for any significant period of time, we would need to transport NGLs by other means. The Minden plant has an existing alternate pipeline connection that would permit the transportation of NGLs to a local fractionator for processing and distribution with sufficient pipeline takeaway and fractionation capacity to handle all of the Minden plant’s NGL production. We do not, however, currently have commercial arrangements in place with the alternative pipeline. While we believe we could establish alternate transportation arrangements, there can be no assurance that we will in fact be able to enter into such arrangements.

Any regulatory expansion of the existing pipeline safety requirements or the adoption of new pipeline safety requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business.

Construction of new assets is subject to regulatory, environmental, political, legal, economic and other risks that may adversely affect financial results.

The construction of additions or modifications to our existing midstream asset systems or propane terminals involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule or within budgeted cost, or at all. We may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The construction of additions to our existing gathering, transportation and propane terminal assets may require us to obtain new rights-of-way prior to constructing new facilities. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines, expand our network of propane terminals, or capitalize on other attractive expansion opportunities. The construction of additional propane terminals may require greater capital investment if the commodity prices of certain supplies such as steel increase. Construction also subjects us to risks related to the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control that could adversely affect results of operations, financial position or cash flows.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants. Our ability to make acquisitions that are accretive to our cash generated from operations per unit is based upon our ability to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them and obtain financing for these acquisitions on economically acceptable terms. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit. Additionally, net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control, and are recognized at DCP Midstream, LLC's basis in the net assets transferred. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. Contributions from DCP Midstream, LLC may significantly increase our debt to capitalization ratios.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, future contract terms with customers, revenues and costs, including synergies;
- an inability to successfully integrate the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- change in competitive landscape;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

In addition, any limitations on our access to substantial new capital to finance strategic acquisitions will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

We do not own all of the land on which our pipelines, facilities and rail terminals are located.

Upon contract lease renewal, we may be subject to more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or if such rights of way lapse or terminate. We obtain the rights to construct and operate our pipelines, surface sites and rail terminals on land owned by third parties and governmental agencies for a specific period of time.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations are subject to many hazards inherent in the gathering, compressing, treating, processing and transporting of natural gas, propane and NGLs, and the storage of propane, including:

- damage to pipelines, plants and terminals, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas, propane, NGLs and other hydrocarbons or losses of natural gas, propane or NGLs as a result of the malfunction of equipment or facilities;
- contaminants in the pipeline system;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in material losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks inherent to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, or may become prohibitively expensive, and we may elect not to carry policy.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Amended Credit Agreement, consisting of a $600.0 million revolving credit facility and a $250.0 million term loan facility for working capital and other general corporate purposes. As of December 31, 2007, the outstanding balance on the revolving credit facility was $530.0 million and the outstanding balance on the term loan facility was $100.0 million.

We continue to have the ability to incur additional debt, subject to limitations within our credit facility. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- an increased amount of cash flow will be required to make interest payments on our debt;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors. In addition, our ability to service debt under our revolving credit facility will depend on market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Restrictions in our credit facility may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain certain financial ratios and tests. Any subsequent replacement of our credit facility or any new indebtedness could have similar or greater restrictions.

Changes in interest rates may adversely impact our ability to issue additional equity or incur debt, as well as the ability of exploration and production companies to finance new drilling programs around our systems.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could impair our ability to issue additional equity to make acquisitions, or incur debt or for other purposes. Increased interest costs could also inhibit the financing of new capital drilling programs by exploration and production companies served by our systems.

Due to our lack of industry diversification, adverse developments in our midstream operations or operating areas would reduce our ability to make distributions to our unitholders.

We rely on the cash flow generated from our midstream energy businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, propane, condensate and NGLs. Due to our lack of diversification in industry type, an adverse development in one of these businesses may have a significant impact on our company.

We are exposed to the credit risks of our key producer customers and propane purchasers, and any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our producer customers and propane purchasers. Any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers or our propane purchasers may be highly leveraged and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us.

Terrorist attacks, the threat of terrorist attacks, and sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001 or the attacks in London, and the threat of future terrorist attacks on our industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies, propane shipments or storage facilities, and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Risks Inherent in an Investment in Our Common Units

Conflicts of interest may exist between individual unitholders and DCP Midstream, LLC, our general partner, which has sole responsibility for conducting our business and managing our operations.

DCP Midstream, LLC owns and controls our general partner. Some of our general partner’s directors, and some of its executive officers, are directors or officers of DCP Midstream, LLC or its parents. Therefore, conflicts of interest may arise between DCP Midstream, LLC and its affiliates and our unitholders. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC’s directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, in resolving conflicts of interest;
- DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, are not limited in their ability to compete with us. Please read “DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us” below;
- once certain requirements are met, our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the special committee of our general partner or our unitholders;
- some officers of DCP Midstream, LLC who provide services to us also will devote significant time to the business of DCP Midstream, LLC, and will be compensated by DCP Midstream, LLC for the services rendered to it;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the Omnibus Agreement, as amended, between us, DCP Midstream, LLC and others will prohibit DCP Midstream, LLC and its affiliates, including ConocoPhillips, Spectra Energy and Spectra Energy Partners, LP, a newly formed master limited partnership controlled by Spectra Energy from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Each of these entities is a large, established participant in the midstream energy business, and each has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, will be material.

Pursuant to the Omnibus Agreement, as amended, we entered into with DCP Midstream, LLC, our general partner and others, DCP Midstream, LLC will receive reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services will be material. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. These factors may reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units and subordinated units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner to make a number of decisions either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- its limited call right;
- its voting rights with respect to the units it owns;
- its registration rights; and
- its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the special committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the special committee of our general partner or holders of our common units and subordinated units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount. Our current distribution level exceeds the highest incentive distribution level.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, in certain situations, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner or its board of directors, and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner will be chosen by the members of our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they may be unable to remove our general partner without its consent.

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least $66^2/_3$% of all outstanding units voting together as a single class is required to remove the general partner. As of December 31, 2007, our general partner and its affiliates owned approximately 34.4% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our current assets include a 25% interest in East Texas, a 40% interest in Discovery, a 45% interest in Black Lake and investments in certain commercial paper and other high grade debt securities, some or all of which may be deemed to be "investment securities" within the meaning of the Investment Company Act of 1940. If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the Commission or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to the unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to the unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in East Texas, Discovery or Black Lake.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- your proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Certain of our investors, including affiliates of our general partner, may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

Pursuant to agreements with investors in private placements effected in 2007, we have filed a registration statement on Form S-3 registering sales by selling unitholders of an aggregate of 5,386,732 of our common units. In addition, in February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 3,571,428, or 50%, of the outstanding subordinated units held by DCP Midstream, LLC into common units. After the conversion, DCP Midstream, LLC holds 4,675,022 common units and 3,571,429 subordinated units, which may convert into common units as early as the first quarter of 2009 if we satisfy certain additional financial tests contained in our partnership agreement.

If investors or affiliates of our general partner holding these units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner has a limited call right that may require the unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, the unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

The liability of holders of limited partner interests may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Holders of limited partner interests could be liable for any and all of our obligations as if such holder were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- the right of holders of limited partner interests to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to the unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS regarding our status as a partnership.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we will be treated as a corporation, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to the unitholder would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to them. Because a tax would be imposed upon us as a corporation, our cash available for distribution to the unitholder would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, which would cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these amendments or other proposals will ultimately be enacted. Moreover, any such modification to federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such legislative changes could negatively impact the value of an investment in our common units. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of such a tax on us by any other state will reduce the cash available for distribution to the unitholder. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this document or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because such costs will reduce our cash available for distribution.

The unitholder may be required to pay taxes on income from us even if the unitholder does not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, the unitholder will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. The unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Tax gain or loss on disposition of common units could be more or less than expected.

If the unitholder sells their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions to the unitholders in excess of the total net taxable income allocated to them for a common unit decreases their tax basis in that common unit, the amount, if any, of such prior excess distributions will, in effect, become taxable income to them if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if the unitholder sells their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, which may be taxable to them. Distributions to non-U.S. persons will be reduced by federal withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If the unitholder is a tax-exempt entity or a non-U.S. person, they should consult their tax advisor before investing in our common units.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the unitholder. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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 common units.

When we issue additional 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 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 common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not reside as a result of investing in our units.

In addition to federal income taxes, the unitholder may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if the unitholder does not live in any of those jurisdictions. The unitholder may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. We own assets and conduct business in the states of Arkansas, Colorado, Connecticut, Indiana, Kentucky, Louisiana, Maine, Maryland, Massachusetts, New Hampshire, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Vermont, Virginia, West Virginia and Wyoming. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax on individuals. A majority of these states impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is the unitholder’s responsibility to file all United States federal, foreign, state and local tax returns.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

As of March 3, 2008, we owned and operated processing plants and gathering systems located in Arkansas, Colorado, Louisiana, Oklahoma, and Wyoming, all within our Natural Gas Services segment, six propane rail terminals located in the Midwest and northeastern United States, one of which is currently idle, and one propane pipeline terminal located in Pennsylvania within our Wholesale Propane Logistics Segment, and two pipelines located in Texas within our NGL Logistics segment. In addition, we own (1) a 40% interest in Discovery Producer Services, LLC, which owns an offshore gathering pipeline, a natural gas processing plant and an NGL fractionator plant in Louisiana operated by a third party, and (2) a 25% interest in DCP East Texas Holdings, LLC, which owns a natural gas processing complex in Texas, all within our Natural Gas Services Segment. We also own a 45% interest in the Black Lake pipeline located in Louisiana and Texas operated by a third party within our NGL Logistics segment, and a 50% interest in a propane rail terminal located in Maine within our Wholesale Propane Logistics segment. For additional details on these plants, propane terminals and pipeline systems, please read “Business — Natural Gas Services Segment,” “Business — Wholesale Propane Logistics Segment” and “Business — NGL Logistics Segment.” We believe that our properties are generally in good condition, well maintained and are generally suitable and adequate to carry on our business at capacity for the foreseeable future.

Our real property falls into two categories: (1) parcels that we own in fee; and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee owner of the lands, as lessors. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Our principal executive offices are located at 370 17th Street, Suite 2775, Denver, Colorado 80202, our telephone number is 303-633-2900 and our website address is *www.dcppartners.com*.

Item 3. *Legal Proceedings*

We are not a party to any significant legal proceedings, other than those listed below, but are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows. Please read “Business — Regulation of Operations” and “Business — Environmental Matters.”

Driver — In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver’s position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

El Paso — In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of our general partner, DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our ownership of this asset. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Item 4. *Submission of Matters to a Vote of Unitholders*

No matters were submitted to a vote of our limited partner unitholders, through solicitation of proxies or otherwise, during 2007.

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Units*

Market Information

Our common units have been listed on the New York Stock Exchange, or the NYSE, under the symbol "DPM" since December 2, 2005. Prior to December 2, 2005, our equity securities were not listed on any exchange or traded on any public trading market. The following table sets forth the high and low closing sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2007, 2006 and for the period from December 7, 2005, the closing of our initial public offering, through December 31, 2005.

Quarter Ended	High	Low	Distribution per Common Unit	Distribution per Subordinated Unit
December 31, 2007	$ 45.95	$ 37.68	$ 0.570	$ 0.570
September 30, 2007	$ 50.50	$ 41.75	$ 0.550	$ 0.550
June 30, 2007	$ 47.00	$ 38.15	$ 0.530	$ 0.530
March 31, 2007	$ 40.06	$ 33.99	$ 0.465	$ 0.465
December 31, 2006	$ 35.28	$ 27.90	$ 0.430	$ 0.430
September 30, 2006	$ 28.95	$ 27.48	$ 0.405	$ 0.405
June 30, 2006	$ 29.40	$ 26.40	$ 0.380	$ 0.380
March 31, 2006	$ 28.25	$ 24.05	$ 0.350	$ 0.350

As of March 3, 2008, there were approximately 63 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record.

We also have 3,571,429 subordinated units outstanding, for which there is no established public trading market. The subordinated units are held by our general partner and its affiliates. Our general partner and its affiliates will receive a quarterly distribution on these units only after sufficient funds have been paid to the common unitholders.

Issuance of Unregistered Units

In February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 50% of the outstanding subordinated units held by DCP Midstream, LLC into common units on a one-for-one basis. Before the conversion, DCP Midstream, LLC held 7,142,857 subordinated units, and after the conversion, DCP Midstream, LLC holds 3,571,429 subordinated units, which may convert into common units as early as the first quarter of 2009 if we satisfy certain additional financial tests contained in our partnership agreement.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

Minimum Quarterly Distribution. The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.35 per unit per quarter, or $1.40 per unit per year. Our current quarterly distribution is $0.57 per unit, or $2.28 per unit annualized. There is no guarantee that we will maintain our current distribution or pay the Minimum Quarterly Distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under our credit agreement. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Capital Requirements — Description of Credit Agreement” for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Prior to June 2007, our general partner was entitled to 2% of all quarterly distributions since inception that we made. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest. The general partner did not participate in certain issuances of common units during 2007. Therefore, the general partner’s 2% interest was reduced to 1.5%. The general partner’s interest may be further reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 48% plus the general partner’s pro rata interest, of the cash we distribute from operating surplus in excess of $0.4025 per unit per quarter. The maximum distribution of 48% plus the general partner’s pro rata interest does not include any distributions that our general partner may receive on limited partner units that it owns.

On January 24, 2008, the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.57 per unit, that was paid on February 14, 2008, to unitholders of record on February 7, 2008. This distribution resulted in our achieving the highest target distribution level pursuant to our partnership agreement.

For additional information on our distributions see Note 11 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Item 6. ***Selected Financial Data***

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from the consolidated financial statements. These consolidated financial statements include our accounts, and prior to December 7, 2005, the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, or DCP Midstream Partners Predecessor, upon the closing of our initial public offering, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business which we acquired from DCP Midstream, LLC in November 2006, and our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services, LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. These were transactions among entities under common control; accordingly, our financial information includes the historical results of our wholesale propane logistics business, Discovery and East Texas for all periods presented. The information contained herein should be read together with, and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial conditions or results of operations. A discussion on our critical accounting estimates is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The table should also be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations:"

	Year Ended December 31, 2007(a)	2006	2005	2004	2003
	(Millions, except per unit data)				
Statements of Operations Data:					
Total operating revenues(b)	$ 873.3	$ 795.8	$ 1,144.3	$ 834.0	$ 765.7
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	826.7	700.4	1,047.3	760.6	706.1
Operating and maintenance expense	32.1	23.7	22.4	19.8	18.3
Depreciation and amortization expense	24.4	12.8	12.7	14.7	15.5
General and administrative expense	24.1	21.0	14.2	8.7	9.5
Total operating costs and expenses	907.3	757.9	1,096.6	803.8	749.4
Operating (loss) income	(34.0)	37.9	47.7	30.2	16.3
Interest income	5.3	6.3	0.5	—	—
Interest expense	(25.8)	(11.5)	(0.8)	—	—
Earnings from equity method investments(c)	39.3	29.2	25.7	17.6	11.2
Impairment of equity method investment(d)	—	—	—	(4.4)	—
Non-controlling interest in income	(0.5)	—	—	—	—
Income tax expense(e)	(0.1)	—	(3.3)	(2.5)	(3.6)
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8	$ 40.9	$ 23.9
Less:					
Net income attributable to predecessor operations(f)	(3.6)	(26.6)	(65.1)	(40.9)	(23.9)
General partner interest in net income	(2.2)	(0.7)	(0.1)	—	—
Net (loss) income allocable to limited partners	$ (21.6)	$ 34.6	$ 4.6	$ —	$ —
Net (loss) income per limited partner unit-basic and diluted	$ (1.05)	$ 1.90	$ 0.20	$ —	$ —
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 500.7	$ 194.7	$ 178.7	$ 179.3	$ 189.6
Total assets	$ 1,120.7	$ 665.9	$ 680.1	$ 472.5	$ 467.4
Accounts payable	$ 165.8	$ 117.3	$ 138.3	$ 63.5	$ 62.3
Long-term debt	$ 630.0	$ 268.0	$ 210.1	$ —	$ —
Partners' equity	$ 168.4	$ 267.7	$ 320.7	$ 400.5	$ 395.1
Other Information:					
Cash distributions declared per unit	$ 2.115	$ 1.565	$ 0.095	N/A	N/A
Cash distributions paid per unit	$ 1.975	$ 1.230	N/A	N/A	N/A

(a) Includes the effect of the acquisition of the Southern Oklahoma system in May 2007 and certain subsidiaries of Momentum Energy Group, Inc. in August 2007.

(b) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel.

(c) Includes the effect of the acquisition of a 25% limited liability company interest in East Texas and a 40% limited liability company interest in Discovery, as well as the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, which was $43.7 million at December 31, 2007.

(d) In 2004, we recorded our proportionate share of an impairment charge on Black Lake totaling $4.4 million.

(e) Income tax expense for 2003 through 2005 is applicable to the results of operations of our wholesale propane logistics business. We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. Income tax expense in 2007 represents a margin-based franchise tax in Texas, or the Texas margin tax. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

(f) Includes the net income attributable to DCP Midstream Partners Predecessor through December 7, 2005, the net income (loss) attributable to our wholesale propane logistics business prior to the date of our acquisition from DCP Midstream, LLC in November 2006, and the net income attributable to the acquisition of a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap prior to the date of our acquisition from DCP Midstream, LLC in July 2007.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this annual report. We refer to the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries upon the closing of our initial public offering as DCP Midstream Partners Predecessor, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business, which we acquired from DCP Midstream, LLC in November 2006, and our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services, LLC, or Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. We refer to DCP Midstream Partners Predecessor, our wholesale propane logistics business, East Texas and Discovery collectively as our "predecessors." The financial information contained herein includes, for each period presented, our accounts, and those of our predecessors.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We operate in three business segments:

- our Natural Gas Services segment, which consists of (1) our Northern Louisiana natural gas gathering, processing and transportation system; (2) our Southern Oklahoma system acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; and (4) certain subsidiaries of Momentum Energy Group, Inc., or MEG, acquired from DCP Midstream, LLC in August 2007;
- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal which became operational in May 2007, and access to several open access pipeline terminals; and
- our NGL Logistics segment, which consists of our interests in three NGL pipelines.

The financial information contained herein includes, for each period presented, our accounts, and the assets, liabilities and operations of (1) DCP Midstream Partners Predecessor for periods prior to December 7, 2005, (2) our wholesale propane logistics business that we acquired in November 2006 and (3) our 25% interest in East Texas, 40% interest in Discovery, and the Swap that we acquired in July 2007, from DCP Midstream, LLC in transactions among entities under common control. Accordingly, our financial information includes the historical results of our predecessors for all periods presented. The historical financial statements of DCP Midstream Partners Predecessor included in this annual report and discussed elsewhere herein include DCP Midstream Partners Predecessor's 50% ownership interest in Black Lake Pipe Line Company, or Black Lake. However, effective December 7, 2005, DCP Midstream, LLC retained a 5% interest and we own a 45% interest in Black Lake.

Recent Events

As of March 3, 2008, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $47.9 million. On March 4, 2008, we entered into an agreement with a counterparty to certain of our swap contracts, whereby our collateral threshold was increased by $20.0 million, resulting in a corresponding reduction of our posted collateral.

In February 2008, we borrowed $35.0 million under our revolving credit facility, $10.0 million of which has since been repaid. In March 2008, we borrowed $30.0 million under our revolving credit facility and retired $30.0 million of outstanding indebtedness under our term loan facility. As a result, we liquidated $30.0 million of restricted investments securing the term loan portion of our credit facility, the proceeds of which were used for working capital purposes. As a result of the above activity, the borrowing capacity under our revolving credit facility was increased to $630.0 million. We had $585.0 million outstanding under our revolving credit facility as of March 6, 2008.

In February 2008, one of our three primary propane suppliers terminated its supply contract with us. We are actively seeking alternative sources of supply and believe such supply sources are available on commercially acceptable terms.

In February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 50% of the outstanding subordinated units held by DCP Midstream, LLC into common units. Prior to the conversion, DCP Midstream, LLC held 7,142,857 subordinated units, and after the conversion, DCP Midstream, LLC holds 3,571,429 subordinated units, which may convert into common units in the first quarter of 2009 if we satisfy certain additional financial tests contained in our partnership agreement.

On January 24, 2008, the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.57 per unit, that was paid on February 14, 2008, to unitholders of record on February 7, 2008. This distribution of $0.57 per unit exceeds the highest target distribution level (see Note 11 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data”).

In January 2008 and December 2007, we received distributions for the fourth quarter of 2007 from Discovery and East Texas of $11.2 million and $6.1 million, respectively. In January 2008, we contributed $1.6 million to Discovery to fund our share of a capital expansion project and in December 2007, we contributed $12.0 million to East Texas, $9.0 million of which was for working capital and $3.0 million was to fund our share of capital projects.

In November 2007, our universal shelf registration statement on Form S-3 was declared effective by the Securities and Exchange Commission, or SEC. The universal shelf registration statement has a maximum aggregate offering price of $1.5 billion, which will allow us to register and issue additional partnership units and debt obligations.

In January 2008, our registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

Subsequent to December 31, 2007, we executed a series of derivative instruments to mitigate a portion of our anticipated commodity exposure. We entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and we entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.

Factors That Significantly Affect Our Results

Upon the closing of our initial public offering, DCP Midstream, LLC contributed to us the assets, liabilities and operations reflected in the historical financial statements, other than the accounts receivable and certain retained liabilities of DCP Midstream Partners Predecessor, and a 5% interest in Black Lake, which were not contributed to us. In November 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC and in July 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap, both from DCP Midstream, LLC, both in transactions among entities under common control. Accordingly, our financial information includes the historical results of our predecessors for each period presented. Prior to November 2006 and July 2007, our financial statements do not give effect to various items that affected our results of operations and liquidity following these acquisitions, including the indebtedness we incurred in conjunction with the closing of these acquisitions, which increased our interest expense from the interest expense reflected in our historical financial statements.

Our results of operations for our Natural Gas Services segment are impacted by increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput. Throughput and capacity utilization rates generally are driven by wellhead production and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate.

Our results of operations for our Natural Gas Services segment are also impacted by the fees we receive and the margins we generate. Our processing contract arrangements can have a significant impact on our profitability and cash flow. Our actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, commodity pricing environment at the time the contract is executed and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, our expansion in regions where certain types of contracts are more common and other market factors.

We have mitigated a portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing operations and certain wholesale propane sales, for both our consolidated entities and equity method investments, through 2013 with natural gas, NGL and crude oil swaps. We mark-to-market these derivative instruments through current period earnings based upon their fair value. While the swaps mitigate the variability of our future cash flows resulting from changes in commodity prices, the mark-to-market method of accounting significantly increases the volatility of our net income because we recognize, in current period operating revenues, all non-cash gains and losses from the mark-to-market of these derivatives.

We primarily use crude oil swaps to mitigate the NGL commodity price risk. As a result, the volatility of our future cash flows and net income may increase if there is a change in the pricing relationship between crude oil and NGLs. We also continue to have price risk exposure related to the portion of our equity volumes that are not covered by these derivatives. In addition, we will be required to provide cash collateral if the fair value of a derivative exceeds the collateral threshold set by the counterparty. Our collateral requirements may be significant.

For 2007, the net loss recorded in operating revenues for these derivatives was $85.2 million. Of the loss, only $5.9 million was related to cash settlements during 2007. The fair value of these derivatives was a net liability of $82.8 million as of December 31, 2007.

Additionally, our results of operations for our Natural Gas Services segment are impacted by market conditions causing variability in natural gas prices. In the past, we have benefited from marketing activities and increased throughput related to atypical and significant differences in natural gas prices at various receipt and delivery points on our Pelico intrastate pipeline system. The market conditions causing the variability in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur.

Our results of operations for our Wholesale Propane Logistics segment are impacted by our ability to balance our purchases and sales of propane, which may increase our exposure to commodity price risks, and by the impact on volume and pricing from weather conditions in the Midwest and northeastern sections of the United States. Our sales of propane may decline when these areas experience periods of milder weather in the winter months, which is when the demand for propane is generally at its highest.

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our NGL pipelines. Our NGL pipelines transport NGLs exclusively on a fee basis.

We completed pipeline integrity testing during 2006, resulting in increased operating costs on Seabreeze, one of our NGL transportation pipelines. The construction of Wilbreeze, an NGL transportation pipeline connecting a DCP Midstream, LLC gas processing plant to the Seabreeze pipeline, was completed in December 2006. The Black Lake pipeline is currently experiencing increased operating costs due to pipeline integrity testing that commenced in 2005 and is expected to continue into 2008. We expect that our results of operations related to our equity interest in the Black Lake pipeline will benefit in 2008 from the completion of this pipeline integrity testing, although it is possible that the integrity testing will result in the need for pipeline repairs, in which case the operations of this pipeline may be interrupted while the repairs are being made. DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing that commenced in

2005 through June 2008, and up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that are determined to be necessary as a result of the pipeline integrity testing. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Any reimbursement of these expenses from DCP Midstream, LLC will be recognized by us as a capital contribution. Seabreeze pipeline integrity testing was completed in 2006 and reimbursements related to these repairs were not significant. We have not made any capital contributions to Black Lake associated with repairing the Black Lake pipeline.

During 2006, we entered into agreements with ConocoPhillips, which expanded the gathering and transportation services between us. As a result of these agreements, 14 and 17 new wells were added to our system during 2007 and 2006, respectively.

Discovery has signed definitive agreements with Chevron Corporation, Royal Dutch Shell plc, and StatoilHydro ASA to construct an approximate 35-mile gathering pipeline lateral to connect Discovery's existing pipeline system to these producers' production facilities for the Tahiti prospect in the deepwater region of the Gulf of Mexico. The Tahiti pipeline lateral expansion is expected to have a design capacity of approximately 200 MMcf/d. In October 2007, Chevron announced that it will face delays and that first production will commence in the third quarter of 2009. In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for remaining costs for the Tahiti pipeline lateral expansion.

Finally, we intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply and Outlook — We believe that current natural gas prices will continue to cause relatively strong levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the number of natural gas wells drilled in the United States has increased overall in recent years, a corresponding increase in production has not been realized, primarily as a result of smaller discoveries and the decline in production from existing wells. We believe that an increase in United States drilling activity, additional sources of supply such as liquefied natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the slowing production of, natural gas in the United States. A number of the areas in which we operate are experiencing significant drilling activity, new increased drilling for deeper natural gas formations, and the implementation of new exploration and production techniques. While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves.

Processing Margins — Our processing profitability is dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. We have mitigated our cash flow exposure to commodity price movements for these commodities by entering into derivative arrangements through 2013 for a portion of our currently anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations. For additional information regarding our derivative activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities."

Wholesale Propane Supply and Outlook — We are a wholesale supplier of propane for the Midwest and northeastern United States, which consists of Connecticut, Maine, Massachusetts, New Hampshire, New York, Ohio, Pennsylvania, Rhode Island and Vermont. Pipeline deliveries to this region in the winter season are generally at capacity and competing propane supply sources, generally consisting of open access propane terminals supplied by interstate pipelines, can have significant supply constraints or outages during peak market conditions. Due to our multiple propane supply sources, propane supply contractual arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable supplies of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating.

Competition — Competition in our Natural Gas Services segment is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

The wholesale propane business is highly competitive in the upper Midwest and northeastern regions of the United States. Our wholesale propane business' competitors include major integrated oil and gas and energy companies, and interstate and intrastate pipelines.

Impact of Inflation — Our industry has experienced rising inflation due to increased activity in the energy sector. Consequently, our costs for chemicals, utilities, materials and supplies, contract labor and major equipment purchases have increased. In the future, we may continue to be affected by inflation. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into our Natural Gas Services segment, our Wholesale Propane Logistics segment and our NGL Logistics segment.

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally under contracts that contain a combination of the following arrangements:

- *Fee-based arrangements* — Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas; and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.

- *Percentage-of-proceeds/index arrangements* — Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percentage-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

In addition to the above contract types our equity method investments may also generate equity earnings for our Natural Gas Services segment under keep-whole arrangements. Under the terms of a keep-whole processing contract, we gather raw natural gas from the producer for processing, sell the NGLs and return to the producer residue natural gas with a Btu content equivalent to the Btu content of the raw natural gas gathered. This arrangement keeps the producer whole to the thermal value of the raw natural gas received. Under this type of contract, we are exposed to the “frac spread.” The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices.

We have mitigated a portion of our currently anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas and crude oil swaps. With these swaps, we expect our cash flow exposure to commodity price movements to be reduced. For additional information regarding our derivative activities, please read “— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities.”

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We are using the mark-to-market method of accounting for all commodity derivative financial instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Colorado, Louisiana, Oklahoma, Texas, Wyoming and the Gulf of Mexico. The Pelico system also receives natural gas produced in Texas through its interconnect with other pipelines that transport natural gas from Texas into western Louisiana. These areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. Our two primary suppliers of natural gas in our Natural Gas Services segment represented approximately 57% of the 349 MMcf/d of natural gas supplied to this system in 2007. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that requires DCP Midstream, LLC to supply Pelico's system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting. We also gather, process and transport natural gas under fee-based transportation contracts.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the Midwest and northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Midwest and the northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our three primary suppliers of propane represented approximately 94% of our propane supplied in 2007. We sell propane on a wholesale basis to retail propane distributors who in turn resell propane to their retail customers.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our retail propane distribution customers with reliable supplies of propane during periods of tight supply, such as the winter months when their retail customers consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are significantly greater than their purchase of propane from us in the summer. We believe these factors generally allow us to maintain our favorable relationship with our customers.

We manage our wholesale propane margins by selling propane to retail propane distributors under annual sales agreements negotiated each spring that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a retail propane distributor desires to purchase propane from us on a fixed price basis, we sometimes enter into fixed price sales agreements with terms of generally up to one year, and we manage this commodity price risk by entering into either offsetting physical purchase agreements or financial derivative instruments, with either DCP Midstream, LLC or third parties, that generally match the quantities of propane subject to these fixed price sales agreements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

NGL Logistics Segment

Our pipelines provide transportation services to customers on a fee basis. We have entered into contractual arrangements with DCP Midstream, LLC that require DCP Midstream, LLC to pay us to transport the NGLs pursuant to a fee-based rate that is applied to the volumes transported. Therefore, the results of operations for this business segment are generally dependent upon the volume of product transported and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. For the Seabreeze and Wilbreeze pipelines, we are responsible for any line loss or gain in NGLs. For the Black Lake pipeline, any line loss or gain in NGLs is allocated to the shipper. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the mixed NGLs from the natural gas. As a result, we have experienced periods in the past, and will likely experience periods in the future, in which higher natural gas prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. In the markets we serve, our pipelines are the sole pipeline facility transporting NGLs from the supply source.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin, including segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, EBITDA and distributable cash flow measures are not accounting principles generally accepted in the United States of America, or GAAP, financial measures. We provide reconciliations of these non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. Our gross margin, segment gross margin, EBITDA and distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner.

Volumes — We view throughput volumes for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as an important factor affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs on our pipelines are substantially dependent upon the quantities of NGLs produced at our processing plants, as well as NGLs produced at other processing plants that have pipeline connections with our NGL pipelines. We regularly monitor producer activity in the areas we serve and on our pipelines, and pursue opportunities to connect new supply to these pipelines.

Gross Margin — We view our gross margin as an important performance measure of the core profitability of our operations. We review our gross margin monthly for consistency and trend analysis.

We define gross margin as total operating revenues less purchases of natural gas, propane and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Our gross margin equals the sum of our segment gross margins. Gross margin is included as a supplemental disclosure because it is a primary performance measure used by management, as it represents the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

Our gross margin and segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin and segment gross margin in the same manner. The following table sets forth our reconciliation of gross margin to its most directly comparable financial measure calculated in accordance with GAAP:

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2007	2006	2005
		(Millions)	
Reconciliation of net (loss) income to gross margin:			
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8
Interest expense	25.8	11.5	0.8
Income tax expense	0.1	—	3.3
Operating and maintenance expense	32.1	23.7	22.4
Depreciation and amortization expense	24.4	12.8	12.7
General and administrative expense	24.1	21.0	14.2
Non-controlling interest in income	0.5	—	—
Interest income	(5.3)	(6.3)	(0.5)
Earnings from equity method investments	(39.3)	(29.2)	(25.7)
Gross margin	$ 46.6	$ 95.4	$ 97.0
Reconciliation of segment net income to segment gross margin:			
Natural Gas Services segment:			
Segment net income	$ 11.6	$ 79.6	$ 71.9
Depreciation and amortization expense	21.9	11.1	10.8
Operating and maintenance expense	20.9	13.5	14.0
Non-controlling interest in income	0.5	—	—
Earnings from equity method investments	(38.7)	(28.9)	(25.3)
Segment gross margin	$ 16.2	$ 75.3	$ 71.4
Wholesale Propane Logistics segment:			
Segment net income	$ 14.0	$ 6.6	$ 12.6
Depreciation and amortization expense	1.1	0.8	1.0
Operating and maintenance expense	10.4	8.6	8.2
Segment gross margin	$ 25.5	$ 16.0	$ 21.8
NGL Logistics segment:			
Segment net income	$ 3.3	$ 1.9	$ 3.1
Depreciation and amortization expense	1.4	0.9	0.9
Operating and maintenance expense	0.8	1.6	0.2
Earnings from equity method investments	(0.6)	(0.3)	(0.4)
Segment gross margin	$ 4.9	$ 4.1	$ 3.8

Operating and Maintenance and General and Administrative Expense — Operating and maintenance expense are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services comprise the most significant portion of our operating and maintenance expense. These expenses are relatively independent of the volumes through our systems, but may fluctuate depending on the activities performed during a specific period.

For the years ended December 31, 2007, 2006 and 2005, our total general and administrative expense was comprised of the following:

	Year Ended December 31, 2007	2006	2005
Affiliate:			
Omnibus Agreement:			
Annual fee	$ 5.0	$ 4.8	$ 0.3
Wholesale propane logistics business	2.0	0.3	—
Southern Oklahoma	0.1	—	—
Discovery	0.1	—	—
Additional services	0.2	—	—
MEG	0.5	—	—
Total Omnibus Agreement	7.9	5.1	0.3
Other — DCP Midstream, LLC	2.1	3.0	8.8
Total affiliate	10.0	8.1	9.1
Third party	14.1	12.9	5.1
Total	$ 24.1	$ 21.0	$ 14.2

A substantial amount of our general and administrative expense is incurred from DCP Midstream, LLC. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee under the Omnibus Agreement for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering.

Following is a summary of the fees we anticipate incurring in 2008 under the Omnibus Agreement and the effective date for these fees:

Terms	Effective Date	Fee (Millions)
Annual fee	2006	$ 5.1
Wholesale propane logistics business	November 2006	2.0
Southern Oklahoma	May 2007	0.2
Discovery	July 2007	0.2
Additional services	August 2007	0.6
MEG	August 2007	1.6
Total		$ 9.7

All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

The Omnibus Agreement also addresses the following matters:

- DCP Midstream, LLC's obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;

- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity derivative instruments, to the extent that such credit support arrangements were in effect as of December 7, 2005 until the earlier of December 7, 2010 or when we obtain an investment grade credit rating from either Moody's Investor Services, Inc. or Standard & Poor's Ratings Group with respect to any of our unsecured indebtedness; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at December 7, 2005 until the expiration of such contracts.

After 2008, the fee will be adjusted by the percentage charge in the Consumer Price Index for the applicable year. In addition, our general partner will have the right to agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses, with the concurrence of the special committee of DCP Midstream GP, LLC's board of directors.

Other general and administrative expenses paid to DCP Midstream, LLC subsequent to our initial public offering include labor and benefit costs related to accounting and internal audit personnel, insurance as well as other administrative costs. Additionally, DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The predecessor's share of those costs was allocated based on the predecessor's proportionate net investment (consisting of property, plant and equipment, net, equity method investments, and intangible assets, net) as compared to DCP Midstream, LLC's net investment. In management's estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

We also incurred third party general and administrative expenses, which were primarily related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

EBITDA and Distributable Cash Flow — We define EBITDA as net income less interest income, plus interest expense, income tax expense and depreciation and amortization expense. EBITDA is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and general partner, and finance maintenance capital expenditures. EBITDA is also a financial measurement that is reported to our lenders, and used as a gauge for compliance with our financial covenants under our credit facility, which requires us to maintain: (1) a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters following the consummation of asset acquisitions in the midstream energy business (including the quarter in which such acquisition is consummated), of not more than 5.50 to 1.0; and (2) an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal to or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination. Our EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA in the same manner.

EBITDA is also used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing methods or capital structure; and
- viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

We define distributable cash flow as net cash provided by operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, net changes in operating assets and liabilities, and other adjustments to reconcile net cash provided by or used in operating activities (see "— Liquidity and Capital Resources" for further definition of maintenance capital expenditures). Maintenance capital expenditures are capital expenditures made where we add on to or improve capital assets owned, or acquire or construct new capital assets, if such expenditures are made to maintain, including over the long term, our operating capacity or revenues. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing distributable cash flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner. Our distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner. The following table sets forth our reconciliation of EBITDA to its most directly comparable financial measure calculated in accordance with GAAP:

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2007	2006 (Millions)	2005
Reconciliation of net (loss) income to EBITDA:			
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8
Interest income	(5.3)	(6.3)	(0.5)
Interest expense	25.8	11.5	0.8
Income tax expense	0.1	—	3.3
Depreciation and amortization expense	24.4	12.8	12.7
EBITDA	$ 29.2	$ 79.9	$ 86.1
Reconciliation of net cash provided by operating activities to EBITDA:			
Net cash provided by operating activities	$ 65.4	$ 94.8	$ 113.0
Interest income	(5.3)	(6.3)	(0.5)
Interest expense	25.8	11.5	0.8
Earnings from equity method investments, net of distributions	0.4	3.3	(11.0)
Income tax expense	0.1	—	3.3
Net changes in operating assets and liabilities	(56.9)	(25.8)	(19.9)
Other, net	(0.3)	2.4	0.4
EBITDA	$ 29.2	$ 79.9	$ 86.1

Critical Accounting Policies and Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations. These accounting policies are described further in Note 2 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Inventories		
Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value.	Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our inventory.	If the market value of our inventory is lower than the cost, we may be exposed to losses that could be material. If propane prices were to decrease by 10% below our December 31, 2007 weighted-average cost, our net income would be affected by approximately $3.7 million.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Goodwill		
Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.	We determine fair value using widely accepted valuation techniques, namely discounted cash flow and market multiple analyses. These techniques are also used when allocating the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	In the third quarter of 2007, we completed our annual impairment testing of goodwill using the methodology described herein, and determined there was no impairment. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to a goodwill impairment charge. We have not recorded goodwill impairment during the year ended December 31, 2007. The carrying value of goodwill as of December 31, 2007 was $80.2 million.
Impairment of Long-Lived Assets		
We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.	Our impairment analyses may require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. These techniques are also used when allocating the purchase price to acquired assets and liabilities.	Using the impairment review methodology described herein, we have not recorded impairment charges during the year ended December 31, 2007. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge. The carrying value of our long-lived assets as of December 31, 2007 was $530.4 million.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Equity Method Investments We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced a decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred.	Our impairment loss calculations require management to apply judgment in estimating future cash flows and asset fair values, including forecasting useful lives of the assets, assessing the probability of differing estimated outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.	Using the impairment review methodology described herein, we have not recorded impairment charges during the year ended December 31, 2007. If the estimated fair value of our equity method investments is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value. The carrying value of our equity method investments as of December 31, 2007 was $187.2 million.
Accounting for Risk Management Activities and Financial Instruments Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings. Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions.	When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.	If our estimates of fair value are inaccurate, we may be exposed to losses or gains that could be material. A 10% difference in our estimated fair value of derivatives at December 31, 2007 would have affected net income by approximately $8.3 million for the year ended December 31, 2007.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Accounting for Equity-Based Compensation		
Our long-term incentive plan permits for the grant of restricted units, phantom units, unit options and substitute awards. Equity-based compensation expense is recognized over the vesting period or service period of the related awards. We estimate the fair value of each award, and the number of awards that will ultimately vest, at the end of each period.	Estimating the fair value of each award, the number of awards that will ultimately vest, and the forfeiture rate requires management to apply judgment to estimate the tenure of our employees and the achievement of certain performance targets over the performance period.	If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in compensation expense.
Accounting for Asset Retirement Obligations		
Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled.	Estimating the fair value of asset retirement obligations requires management to apply judgment to evaluate the necessary retirement activities, estimate the costs to perform those activities, including the timing and duration of potential future retirement activities, and estimate the risk free interest rate. When making these assumptions, we consider a number of factors, including historical retirement costs, the location and complexity of the asset and general economic conditions.	If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in our asset retirement obligations. Establishing an asset retirement obligation has no initial impact on net income. A 10% change in depreciation and accretion expense associated with our asset retirement obligations during the year ended December 31, 2007, would not have had a significant effect on net income.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31, 2007	2006	2005	Variance 2007 vs. 2006 Increase (Decrease)	Percent	Variance 2006 vs. 2005 Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues:							
Natural Gas Services(a)	$ 404.1	$ 415.3	$ 592.8	$ (11.2)	(2.7)%	$ (177.5)	(29.9)%
Wholesale Propane Logistics	459.6	375.2	359.8	84.4	22.5%	15.4	4.3%
NGL Logistics	9.6	5.3	191.7	4.3	81.1%	(186.4)	(97.2)%
Total operating revenues	873.3	795.8	1,144.3	77.5	9.7%	(348.5)	(30.5)%
Gross margin(b):							
Natural Gas Services	16.2	75.3	71.4	(59.1)	(78.4)%	3.9	5.5%
Wholesale Propane Logistics	25.5	16.0	21.8	9.5	59.4%	(5.8)	(26.6)%
NGL Logistics	4.9	4.1	3.8	0.8	19.5%	0.3	7.9%
Total gross margin	46.6	95.4	97.0	(48.8)	(51.2)%	(1.6)	(1.6)%
Operating and maintenance expense	(32.1)	(23.7)	(22.4)	8.4	35.4%	1.3	5.8%
General and administrative expense	(24.1)	(21.0)	(14.2)	3.1	14.8%	6.8	47.9%
Earnings from equity method investments(c)	39.3	29.2	25.7	10.1	34.6%	3.5	13.6%
Non-controlling interest in income	(0.5)	—	—	0.5	100.0%	—	—
EBITDA(d)	29.2	79.9	86.1	(50.7)	(63.5)%	(6.2)	(7.2)%
Depreciation and amortization expense	(24.4)	(12.8)	(12.7)	11.6	90.6%	0.1	0.8%
Interest income	5.3	6.3	0.5	(1.0)	(15.9)%	5.8	*
Interest expense	(25.8)	(11.5)	(0.8)	14.3	*	10.7	*
Income tax expense	(0.1)	—	(3.3)	0.1	100.0%	(3.3)	(100.0)%
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8	$ (77.7)	*	$ (7.9)	(11.3)%
Operating data:							
Natural gas throughput (MMcf/d)(c)	756	666	629	90	13.5%	37	5.9%
NGL gross production (Bbls/d)(c)	22,122	19,485	17,562	2,637	13.5%	1,923	10.9%
Propane sales volume (Bbls/d)	22,798	21,259	22,604	1,539	7.2%	(1,345)	(6.0)%
NGL pipelines throughput (Bbls/d)(c)	28,961	25,040	20,565	3,921	15.7%	4,475	21.8%

* Percentage change is greater than 100%.

(a) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels at $66.72 per barrel.

(b) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs, and segment gross margin for each segment consists of total operating revenues for that segment, less commodity purchases for that segment. Please read "How We Evaluate Our Operations" above.

(c) Includes our proportionate share of the throughput volumes and earnings of Black Lake, East Texas and Discovery. Earnings for Discovery and Black Lake include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the investments.

(d) EBITDA consists of net (loss) income less interest income plus interest expense, income tax expense, and depreciation and amortization expense. Please read "How We Evaluate Our Operations" above.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues — Total operating revenues increased in 2007 compared to 2006, primarily due to the following:

- $88.1 million increase attributable to higher propane prices and higher sales volumes for our Wholesale Propane Logistics segment;
- $66.2 million increase primarily attributable to an increase in natural gas, NGL and condensate sales volumes, including increases as a result of the MEG and Southern Oklahoma acquisitions, and increases in NGL and condensate prices, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation for our Natural Gas Services segment;
- $7.3 million increase in transportation revenue primarily attributable to an increase in throughput volumes in our Natural Gas Services segment; and
- $3.4 million increase due to changes in product mix and increased volumes for our NGL Logistics segment; offset by
- $87.5 million decrease related to commodity derivative activity, an increase of $0.2 million of which is included in sales of natural gas, NGLs and condensate, and a decrease of $87.7 million of which is included in losses from derivative activity.

Gross Margin — Gross margin decreased in 2007 compared to 2006, primarily due to the following:

- $59.1 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity, and a decrease in marketing margins from the decline in the differences of natural gas prices at various receipt and delivery points across our Pelico system, offset by an increase in NGL and condensate production, mainly as a result of the MEG and Southern Oklahoma acquisitions, an increase in natural gas throughput volumes and higher contractual fees charged to customers; offset by
- $9.5 million increase for our Wholesale Propane Logistics segment due to higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, decreased non-cash lower of cost or market inventory adjustments recognized in 2007, and higher sales volumes primarily due to the completion of the Midland terminal, which became operational in May 2007, partially offset by a decrease related to commodity derivative activity; and
- $0.8 million increase for our NGL Logistics segment primarily attributable to changes in product mix and increased volumes, as well as increased transportation revenue.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions, higher labor and benefits and pipeline integrity costs in our Natural Gas Services segment, and higher operating and maintenance expense at the Midland terminal, which became operational in May 2007 in our Wholesale Propane Logistics segment, offset by lower pipeline integrity costs on our Seabreeze pipeline in our NGL Logistics segment.

General and Administrative Expense — General and administrative expense increased in 2007 compared to 2006, primarily as a result of increased due diligence and acquisition costs, increased fees under our omnibus agreement with DCP Midstream, LLC and increased labor and benefit costs, partially offset by decreases in audit and public company costs.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2007 compared to 2006, primarily due to increased equity earnings of $7.2 million from Discovery, $2.6 million from East Texas and $0.3 million from Black Lake.

Non-Controlling Interest in Income — Non-controlling interest in income reduced income by $0.5 million in 2007, and represents the non-controlling interest holders' portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of acquisitions.

Interest Expense — Interest expense increased in 2007 compared to 2006, primarily as a result of financing the 2007 acquisitions.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased in 2006 compared to 2005, primarily due to the following:

- $190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline, primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation arrangement for our NGL Logistics segment; and
- $181.3 million decrease attributable primarily to lower natural gas prices and sales volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, partially offset by an increase in NGL and condensate prices and sales volumes for our Natural Gas Services segment; offset by
- $15.2 million increase attributable to higher propane prices, which were offset by lower sales volumes for our Wholesale Propane Logistics segment;
- $4.7 million increase in transportation revenue primarily attributable to an increase in volumes and a change in contract terms in December 2005 for our Seabreeze pipeline, from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and
- $3.2 million increase related to commodity derivative activity.

Gross Margin — Gross margin decreased in 2006 compared to 2005, primarily due to the following:

- $5.8 million decrease due to non-cash lower of cost or market inventory adjustments, decreased sales volumes, and increased product and transportation costs for our Wholesale Propane Logistics segment; offset by
- $3.9 million increase for our Natural Gas Services segment primarily due to higher NGL and condensate prices, and an increase in natural gas throughput volumes, offset by lower natural gas prices, decreases due to a change in contract mix, and decreased marketing activity and throughput across the Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system, which impacted gross margin more significantly in 2005 than in 2006. The market

conditions causing the differentials in natural gas prices at various receipt and delivery points may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

- $0.3 million increase attributable to increased transportation revenue and higher volumes on our Seabreeze pipeline for our NGL Logistics segment.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2006 compared to 2005, primarily as a result of higher pipeline integrity costs, increased labor and benefit costs, an increase in lease expense and the settlement of a commercial dispute.

General and Administrative Expense — General and administrative expense increased in 2006 primarily as a result of increased audit fees, due diligence and acquisition costs, costs incurred related to the Sarbanes-Oxley Act of 2002, labor and benefit costs, and insurance premiums.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2006 compared to 2005, primarily due to increased equity earnings of $6.1 million from Discovery, offset by decreased equity earnings of $2.5 million from East Texas and $0.1 million from Black Lake.

Depreciation and Amortization Expense — Depreciation and amortization expense was relatively constant in 2006 and 2005.

Income Tax Expense — We incurred no income tax expense in 2006, due to the change in tax status of our wholesale propane logistics business in December 2005. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Results of Operations — Natural Gas Services Segment

This segment consists of our Northern Louisiana system, the Southern Oklahoma system acquired in May 2007, a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery, and the Swap, acquired in July 2007, and certain subsidiaries of MEG, acquired in August 2007.

	Year Ended December 31,			Variance 2007 vs. 2006		Variance 2006 vs. 2005	
	2007	2006	2005	Amount	Percent	Amount	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 458.2	$ 391.8	$ 570.9	$ 66.4	16.9%	$ (179.1)	(31.4)%
Transportation and processing services	29.4	23.5	22.6	5.9	25.1%	0.9	4.0%
Losses from derivative activity(a)	(83.5)	—	(0.7)	(83.5)	*	0.7	(100.0)%
Total operating revenues	404.1	415.3	592.8	(11.2)	(2.7)%	(177.5)	(29.9)%
Purchases of natural gas and NGLs	387.9	340.0	521.4	47.9	14.1%	(181.4)	(34.8)%
Segment gross margin(b)	16.2	75.3	71.4	(59.1)	(78.5)%	3.9	5.5%
Operating and maintenance expense	(20.9)	(13.5)	(14.0)	7.4	54.8%	(0.5)	(3.6)%
Depreciation and amortization expense	(21.9)	(11.1)	(10.8)	10.8	97.3%	0.3	2.8%
Earnings from equity method investments(c)	38.7	28.9	25.3	9.8	33.9%	3.6	14.2%
Non-controlling interest in income	(0.5)	—	—	0.5	100.0%	—	—
Segment net income	$ 11.6	$ 79.6	$ 71.9	$ (68.0)	(85.4)%	$ 7.7	10.7%
Operating data:							
Natural gas throughput (MMcf/d)(c)	756	666	629	90	13.5%	37	5.9%
NGL gross production (Bbls/d)	22,122	19,485	17,562	2,637	13.5%	1,923	10.9%

* Percentage change is greater than 100%.

(a) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap is for a total of approximately 1.9 million barrels through 2012, at $66.72 per barrel.

(b) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read "How We Evaluate Our Operations" above.

(c) Includes our proportionate share of the throughput volumes and earnings of East Texas and Discovery, and the amortization of the net difference between the carrying amount of Discovery and the underlying equity of Discovery, for all periods presented.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues — Total operating revenues decreased in 2007 compared to 2006, primarily due to the following:

- $83.3 million decrease related to commodity derivative activity, an increase of $0.2 million of which is included in sales of natural gas, NGLs and condensate, and a decrease of $83.5 million of which is included in losses from derivative activity; offset by
- $49.0 million increase attributable to an increase in natural gas, NGL and condensate sales volumes, primarily as a result of the MEG and Southern Oklahoma acquisitions, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation;

- $17.2 million increase attributable to increased NGL and condensate prices; and
- $5.9 million increase in transportation and processing services revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased in 2007 compared to 2006, primarily due to increased natural gas purchase volumes primarily as a result of the MEG and Southern Oklahoma acquisitions, offset by decreased natural gas purchased volumes primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation.

Segment Gross Margin — Segment gross margin decreased in 2007 compared to 2006, primarily as a result of the following:

- $83.3 million decrease related to commodity derivative activity;
- $2.5 million decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, which were atypically high in 2006; partially offset by
- $25.2 million increase primarily attributable to an increase in NGL and condensate production, partially as a result of the MEG and Southern Oklahoma acquisitions, and an increase in natural gas throughput volumes;
- $1.0 million increase primarily attributable to higher contractual fees charged to customers; and
- $0.5 million increase primarily attributable to favorable frac spreads.

NGL production and natural gas transported and/or processed during 2007 increased compared to 2006. These increases were due primarily to increased volumes from Discovery, as well as an increase in volumes from the MEG and Southern Oklahoma acquisitions, partially offset by decreased volumes from Pelico.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions, and higher labor and benefits and pipeline integrity costs.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of the MEG and Southern Oklahoma acquisitions.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2007 compared to 2006, primarily due to increased equity earnings of $7.2 million from Discovery and $2.6 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Increased equity earnings from Discovery were the result of an increase in Discovery's net income of $18.0 million, or 60%, due primarily to $39.0 million higher gross processing margins resulting from higher NGL sales volumes and NGL prices, partially offset by $9.9 million lower fee-based transportation, gathering, processing and fractionation revenues, $5.9 million higher operating and maintenance expense and $2.2 million higher other expenses. In addition, exceptionally strong commodity margins compelled Discovery's customers to process their natural gas rather than by-pass, which led to higher product sales revenues on Discovery's percent-of-proceeds and keep-whole processing contracts.
- Increased equity earnings from East Texas were the result of an increase in East Texas's net income of $10.7 million, or 22%, due primarily to a $28.5 million increase as a result of higher commodity prices and a $1.1 million decrease in income tax expense due to recording a deferred tax liability of $1.8 million in 2006 related to the Texas margin tax; partially offset by an $11.6 million decrease due to a decline in natural gas volumes, a $3.0 million decrease due to decreased fee-based revenue, and an increase in operating and maintenance expenses of $2.8 million, primarily due to increased contract

services, materials and supplies, and labor an benefits, increased depreciation expense of $1.2 million due to the addition of a new pipeline, and increased general and administrative expenses of $0.6 million, primarily due to higher allocated costs from DCP Midstream, LLC.

Non-Controlling Interest in Income — Non-controlling interest in income reduced income by $0.5 million in 2007, and represents the non-controlling interest holders' portion of the net income of our Collbran Valley Gas Gathering system joint venture, acquired in the MEG acquisition.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased in 2006 compared to 2005, primarily due to the following:

- $114.1 million decrease attributable to a decrease in natural gas sales volumes and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation; and
- $87.3 million decrease attributable to a decrease in natural gas prices; offset by
- $10.1 million increase primarily attributable to higher NGL and condensate sales volumes;
- $10.0 million increase attributable to an increase in NGL and condensate prices;
- $2.9 million increase related to commodity derivative activity; and
- $0.9 million increase in transportation revenue primarily attributable to an increase in natural gas throughput.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs decreased in 2006 compared to 2005, primarily due to lower costs of raw natural gas supply, driven by lower natural gas prices and decreased purchased volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico purchases from a gross presentation to a net presentation, partially offset by higher NGL and condensate prices and NGL and condensate purchased volumes.

Segment Gross Margin — Segment gross margin increased in 2006 compared to 2005, primarily as a result of the following:

- $6.2 million increase attributable to higher NGL and condensate prices and favorable frac spreads, partially offset by lower natural gas prices. The frac spreads that existed during 2006 were higher than in recent years and may not continue in the future;
- $5.2 million increase primarily attributable to an increase in natural gas throughput volumes;
- $2.9 million increase related to commodity derivative activity; and
- $0.5 million increase attributable to higher contractual fees charged to customers related to pipeline imbalances; offset by
- $5.1 million decrease primarily attributable to a change in contract mix;
- $4.0 million decrease attributable to a decrease in marketing activity and throughput across our Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and
- $1.8 million decrease attributable to higher netback prices paid to the producers at Minden and Ada.

NGL production during 2006 increased compared to 2005, due primarily to increased volumes at Discovery and unfavorable market economics for processing NGLs in the fourth quarter of 2005. Natural gas transported and/or processed during 2006 increased compared to 2005, primarily as a result of higher natural gas volumes at Discovery and for our Pelico system, offset by lower volumes at East Texas.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2006 compared to 2005, primarily as a result of lower costs associated with repairs and maintenance.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2006 compared to 2005, primarily due to increased equity earnings of $6.1 million from Discovery, partially offset by decreased equity earnings of $2.5 million from East Texas. Increased equity earnings were primarily the result of the following variances, each representing 100% of the earnings drivers for East Texas and Discovery:

- Decreased equity earnings from East Texas were the result of a decrease in East Texas's net income of $10.0 million, or 17%, due primarily to a $15.7 million decrease due to natural gas volumes and a $3.7 million decrease due to decreased fee-based revenue, offset by a $17.3 million increase due to increases in overall contract yield and higher condensate sales due to higher crude oil prices, an increase in operating and maintenance expenses of $4.2 million, primarily due to increased contract services, materials and supplies, and labor and benefits, an increase in general and administrative expenses of $1.6 million, primarily due to higher allocated costs from DCP Midstream, LLC of $1.5 million due to higher overall DCP Midstream, LLC general and administrative expenses and an increase of $1.8 million in income tax expense due to recording deferred taxes in 2006 related to the Texas margin tax.

- Increased equity earnings from Discovery were the result of our purchase of an additional 6.67% interest in Discovery, as well as an increase in Discovery's income before cumulative effect of change in accounting principle of $9.3 million, or 44%, due primarily to $18.1 million higher gross processing margins and $7.5 million higher revenues from TGP and TETCO open seasons, partially offset by $12.9 million higher operating and maintenance and $3.8 million lower gathering revenues. The open seasons provided outlets for natural gas that was stranded following damage to third-party facilities during hurricanes Katrina and Rita. TGP's open season contract came to an end in early 2006.

Results of Operations — Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

	Year Ended December 31, 2007	2006	2005	Variance 2007 vs. 2006 Amount	Percent	Variance 2006 vs. 2005 Amount	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 463.1	$ 375.0	$ 359.8	$ 88.1	23.5%	$ 15.2	4.2%
Transportation and processing services	0.6	0.1	0.2	0.5	*	(0.1)	(50.0)%
(Losses) gains from derivative activity	(4.1)	0.1	(0.2)	(4.2)	*	0.3	*
Total operating revenues	459.6	375.2	359.8	84.4	22.5%	15.4	4.3%
Purchases of propane	434.1	359.2	338.0	74.9	20.9%	21.2	6.3%
Segment gross margin(a)	25.5	16.0	21.8	9.5	59.4%	(5.8)	(26.6)%
Operating and maintenance expense	(10.4)	(8.6)	(8.2)	1.8	20.9%	0.4	4.9
Depreciation and amortization expense	(1.1)	(0.8)	(1.0)	0.3	37.5%	(0.2)	(20.0)%
Segment net income	$ 14.0	$ 6.6	$ 12.6	$ 7.4	*	$ (6.0)	(47.6)%
Operating Data:							
Propane sales volume (Bbls/d)	22,798	21,259	22,604	1,539	7.2%	(1,345)	(6.0)%

* Percentage change is greater than 100%.

(a) Segment gross margin consists of total operating revenues less purchases of propane. Please read "How We Evaluate Our Operations" above.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues — Total operating revenues increased in 2007 compared to 2006, primarily due to the following:

- $60.8 million increase attributable to higher propane prices;
- $27.3 million increase attributable to higher propane sales volumes as a result of colder weather in the northeastern United States and the completion of the Midland terminal, which became operational in May 2007; and
- $0.5 million increase in transportation and processing services; offset by
- $4.2 million decrease related to commodity derivative activity.

Purchases of Propane — Purchases of propane increased in 2007 compared to 2006, primarily due to increased prices and purchased volumes, primarily due to colder weather in the northeastern United States and increased purchased volumes due to the completion of the Midland terminal, which became operational in May 2007, partially offset by decreased non-cash lower of cost or market inventory adjustments recognized in 2007.

Segment Gross Margin — Segment gross margin increased in 2007 compared to 2006, primarily as a result of higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, decreased non-cash lower of cost or market inventory adjustments recognized in 2007, and higher sales volumes primarily due to the completion of the Midland terminal, which became operational in May 2007, partially offset by a decrease related to commodity derivative activity.

Propane sales volume increased in 2007 compared to 2006, due primarily to colder weather in the northeastern United States and the addition of the Midland terminal, which became operational in May 2007.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2007 compared to 2006, primarily due to operating and maintenance expense at the Midland terminal, which became operational in May 2007.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues increased in 2006 compared to 2005, primarily due to the following:

- $36.6 million increase attributable to higher propane prices; and
- $0.3 million increase related to commodity derivative activity; offset by
- $21.4 million decrease attributable to lower propane sales volumes; and
- $0.1 million decrease in transportation revenues.

Purchases of Propane — Purchases of propane increased in 2006 compared to 2005, primarily due to increased product and transportation costs, and non-cash lower of cost or market inventory adjustments partially offset by a decrease in volume.

Segment Gross Margin — Segment gross margin decreased in 2006 compared to 2005, primarily as a result of decreased sales volumes, non-cash lower of cost or market inventory adjustments, and increased product and transportation costs.

Propane sales volume decreased in 2006 compared to 2005, due primarily to milder weather in the northeastern United States in 2006.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2006 compared to 2005, primarily as a result of higher labor costs and an increase in lease expenses.

Results of Operations — NGL Logistics Segment

This segment includes our Seabreeze and Wilbreeze NGL transportation pipelines and our 45% interest in Black Lake.

	Year Ended December 31,			Variance 2007 vs. 2006		Variance 2006 vs. 2005	
	2007	2006	2005	Amount	Percent	Amount	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$ 4.5	$ 1.1	$ 191.4	$ 3.4	*	$ (190.3)	(99.4)%
Transportation and processing services	5.1	4.2	0.3	0.9	21.4%	3.9	*
Total operating revenues	9.6	5.3	191.7	4.3	81.1%	(186.4)	(97.2)%
Purchases of NGLs	4.7	1.2	187.9	3.5	*	(186.7)	(99.4)%
Segment gross margin(a)	4.9	4.1	3.8	0.8	19.5%	0.3	7.9%
Operating and maintenance expense	(0.8)	(1.6)	(0.2)	(0.8)	(50.0)%	1.4	*
Depreciation and amortization expense	(1.4)	(0.9)	(0.9)	0.5	55.6%	—	—
Earnings from equity method investment(b)	0.6	0.3	0.4	0.3	100.0%	(0.1)	(25.0)%
Segment net income	$ 3.3	$ 1.9	$ 3.1	$ 1.4	73.7%	$ (1.2)	(38.7)%
Operating data:							
NGL pipelines throughput (Bbls/d)(b)	28,961	25,040	20,565	3,921	15.7%	4,475	21.8%

* Percentage change is greater than 100%.

(a) Segment gross margin consists of total operating revenues less purchases of natural gas and NGLs. Please read “How We Evaluate Our Operations” above.

(b) Includes our proportionate share of the throughput volumes and earnings of Black Lake.

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

Total Operating Revenues — Total operating revenues increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes, as well as increased transportation revenue. Increased volumes and transportation revenue are primarily as a result of the addition of our Wilbreeze pipeline in December 2006.

Purchases of NGLs — Purchases of NGLs increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes.

Segment Gross Margin — Segment gross margin increased in 2007 compared to 2006, primarily due to changes in product mix and increased volumes, as well as increased transportation revenue.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2007 as compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2007 compared to 2006, primarily due to lower pipeline integrity costs on our Seabreeze pipeline.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2007 compared to 2006, primarily as a result of the addition of our Wilbreeze pipeline.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2007 compared to 2006, due to higher Black Lake revenues, partially offset by increased project costs.

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

Total Operating Revenues — Total operating revenues decreased in 2006 compared to 2005, primarily due to the following:

- $190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation agreement; offset by
- $3.9 million increase in transportation revenue attributable to an increase in volumes and a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Purchases of NGLs — Purchases of NGLs decreased in 2006 compared to 2005, attributable to lower purchases due to the change in contract terms in December 2005 from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

Segment Gross Margin — Segment gross margin increased in 2006 compared to 2005, primarily due to increased transportation revenue and higher volumes on our Seabreeze pipeline.

Overall, our NGL pipelines experienced an increase in throughput volumes during 2006 as compared to 2005, partially as result of a decrease in September 2005 volumes related to the impact of hurricane Katrina.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2006 compared to 2005, primarily as a result of higher costs associated with asset integrity, the settlement of a commercial dispute, and equipment rentals.

Earnings from Equity Method Investment — Earnings from equity method investment remained relatively constant in 2006 and 2005.

Liquidity and Capital Resources

Our Predecessor's sources of liquidity, prior to their acquisition by us, included cash generated from operations and funding from DCP Midstream, LLC. Our Predecessor's cash receipts were deposited in DCP Midstream, LLC's bank accounts and all cash disbursements were made from these accounts. Cash transactions for our Predecessors were handled by DCP Midstream, LLC and were reflected in partners' equity as intercompany advances from DCP Midstream, LLC. Following the acquisition of our Predecessor operations, we maintain our own bank accounts, which are managed by DCP Midstream, LLC.

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our equity method investments;
- borrowings under our revolving credit facility;
- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units; and
- debt offerings.

We anticipate our more significant uses of resources to include:

- capital expenditures;
- contributions to our equity method investments to finance our share of their capital expenditures;
- business and asset acquisitions;

- collateral with counterparties to our swap contracts to secure potential exposure under these contracts; and
- quarterly distributions to our unitholders.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure and acquisition requirements, and quarterly cash distributions for the next twelve months. Our commodity derivative program, as well as any future derivatives we enter into, may require us to post collateral, which at times, may be significant, depending on commodity price movements.

Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. We have mitigated a portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas and crude oil swaps. For additional information regarding our derivative activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities."

The counterparties to each of our swap contracts are investment-grade rated financial institutions. Under these contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined "collateral threshold." The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a single pricing point at which our swap contracts will meet the collateral thresholds. As of March 3, 2008, we posted collateral with certain counterparties of approximately $47.9 million. On March 4, 2008, we entered into an agreement with a counterparty to certain of our swap contracts, whereby our collateral threshold was increased by $20.0 million, resulting in a corresponding reduction of our posted collateral. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for hedges guaranteed by DCP Midstream, LLC are generally dependent on DCP Midstream, LLC's credit rating and the thresholds would be reduced to $0 in the event DCP Midstream, LLC's credit rating were to fall below investment grade. DCP Midstream, LLC has provided guarantees to support certain natural gas, NGL and condensate hedging contracts through 2010 that were executed prior to our initial public offering.

Discovery is owned 40% by us and 60% by Williams Partners, LP. Discovery is managed by a two-member management committee, consisting of one representative from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in Discovery. All actions and decisions relating to Discovery require the unanimous approval of the owners except for a few limited situations. Discovery must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions. In addition, the owners are required to offer to Discovery all opportunities to construct pipeline laterals within an "area of interest." Calls for capital contributions are determined by a vote of the management committee and require unanimous approval of both owners in most instances.

East Texas is owned 25% by us and 75% by DCP Midstream, LLC. East Texas is managed by a four-member management committee, consisting of two representatives from each owner. The members of the management committee have voting power corresponding to their respective ownership interests in East Texas. Most significant actions relating to East Texas require the unanimous approval of both owners. East Texas must make quarterly distributions of available cash (generally, cash from operations less required and discretionary reserves) to its owners. The management committee, by majority approval, will determine the amount of the distributions. Calls for capital contributions are determined by a vote of the management committee and require unanimous approval of both owners except in certain situations, such as the breach or default of a material agreement or payment obligation, that are reasonably likely to have a material adverse effect on the business, operations or financial condition of East Texas.

Working Capital — Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced by our quarterly distributions, which are required under the terms of our partnership agreement based on Available Cash, as defined in the partnership agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, along with other business factors that affect our net income and cash flows. Our working capital is also impacted by the timing of operating cash receipts and disbursements, borrowings of and payments on debt, capital expenditures, and increases or decreases in restricted investments and other long-term assets.

We had a working capital deficit of $1.1 million as of December 31, 2007 and working capital of $33.1 million as of December 31, 2006. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital requirements will continue to be impacted by the factors identified above.

Cash Flow — Net cash provided by or used in operating, investing and financing activities was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Net cash provided by operating activities	$ 65.4	$ 94.8	$ 113.0
Net cash used in investing activities	$ (521.7)	$ (93.8)	$ (130.4)
Net cash provided by financing activities	$ 434.6	$ 3.0	$ 59.6

Net Cash Provided by Operating Activities — The changes in net cash provided by operating activities are attributable to our net income adjusted for non-cash charges as presented in the consolidated statements of cash flows and changes in working capital as discussed above.

We and our predecessors received cash distributions from equity method investments of $38.9 million, $25.9 million and $36.7 million during the years ended December 31, 2007, 2006 and 2005, respectively. Earnings exceeded distributions by $0.4 million and $3.3 million for the years ended December 31, 2007 and 2006, respectively, and distributions exceeded earnings by $11.0 million for the year ended December 31, 2005.

Net Cash Used in Investing Activities — Net cash used in investing activities during 2007 was primarily used for: (1) asset acquisitions of $191.3 million; (2) acquisition of equity method investments of $153.3 million; (3) acquisition of the MEG subsidiaries of $142.0 million; (4) capital expenditures of $21.3 million, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities and (5) investments in equity method investments of $16.3 million; which were partially offset by (6) net proceeds from available-for-sale securities of $2.4 million.

During 2007, we acquired Discovery, East Texas and the Swap from DCP Midstream, LLC for an initial cash outlay of approximately $243.7 million. The historical value of the assets acquired of approximately $153.3 million is reflected in “net cash used in investing activities.” The remaining $90.4 million is reflected in “net cash provided by financing activities.”

During 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, for an initial cash outlay of approximately $67.4 million. The historical value of the assets acquired of approximately $56.7 million is reflected in “net cash used in investing activities.” The remaining $10.7 million is reflected in “net cash provided by financing activities” as the excess of the purchase price over the acquired assets.

We invested cash in equity method investments of $16.3 million, $11.1 million and $20.5 million during the years ended December 31, 2007, 2006 and 2005, respectively, of which $6.9 million, $11.1 million and $7.6 million, respectively, was to fund our share of capital expansion projects, $9.4 million in 2007 was to fund working capital needs and $12.9 million in 2005 was for the purchase of an additional 6.67% ownership interest in Discovery.

Net cash used in investing activities in 2006 and 2005 was also used for capital expenditures, which generally consisted of expenditures for construction and expansion of our infrastructure in addition to well connections and other upgrades to our existing facilities. Net cash used in investing activities in 2005 also consisted of purchases of available-for-sale securities in the amount of $100.1 million to provide collateral for the term loan portion of our credit facility.

Net Cash Provided By Financing Activities — Net cash provided by financing activities during 2007 was comprised of borrowings of $579.0 million and the issuance of common units for $228.5 million, net of offering costs, and contributions from non-controlling interests of $3.4 million, offset by repayment of debt of $217.0 million, the excess of purchase price over the acquired assets attributable to a payment related to our acquisition of Discovery, East Texas and the Swap of $90.4 million and of our wholesale propane logistics business of $9.9 million, distributions to our unitholders of $44.0 million, and net change in advances from DCP Midstream, LLC of $14.6 million.

During 2007, we had the following borrowings:

- $11.0 million under our revolving credit facility to fund the purchase of the Laser assets from Midstream;
- $89.0 million under our revolving credit facility to partially fund the Southern Oklahoma acquisition;
- $88.0 million under a bridge loan to partially fund the Southern Oklahoma acquisition, which was extinguished with borrowings under our revolving credit facility;
- $246.0 million from our revolving credit facility to finance the acquisition of our interests in East Texas and Discovery;
- $100.0 million from our term loan facility and $35.0 million from our revolving credit facility to finance the MEG acquisition and for general corporate purposes; and
- $10.0 million from our revolving credit facility for general corporate purposes, which was subsequently repaid.

Net cash provided by financing activities in 2006 was primarily comprised of borrowings on our credit facility, which we used to fund the acquisition of our wholesale propane logistics business, partially offset by distributions to our unitholders, repayments of debt, changes in parent advances and the excess purchase price of our wholesale propane logistics business over its historical basis. Net cash provided by financing activities in 2005 was a result of proceeds from the issuance of common units and proceeds from borrowings on our credit facility, partially offset by distributions to and changes in advances from DCP Midstream, LLC. Net cash provided by (used in) financing activities in 2005 represents the pass through of our net cash flows to DCP Midstream, LLC under its cash management program as discussed above.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 11 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Capital Requirements — The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- maintenance capital expenditures, which are cash expenditures where we add on to or improve capital assets owned or acquire or construct new capital assets if such expenditures are made to maintain, including over the long term, our operating capacity or revenues; and
- expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks,

tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues.

Given our objective of growth through acquisitions, expansion of existing assets and other internal growth projects, we anticipate that we will continue to invest significant amounts of capital to grow. We actively consider a variety of assets for potential acquisition and expansion projects.

We have budgeted maintenance capital expenditures of $5.3 million and expansion capital expenditures of $2.9 million for the year ending December 31, 2008, excluding acquisitions. In addition, we anticipate maintenance capital expenditures of $2.7 million for our 25% interest in East Texas and $1.9 million for our 40% interest in Discovery for the year ending December 31, 2008. We also anticipate expansion capital expenditures of $3.0 million for our 25% interest in East Texas and $5.3 million for our 40% interest in Discovery for the year ending December 31, 2008. We may be required to contribute cash to East Texas and Discovery to cover our respective share of expansion capital expenditures at both East Texas and Discovery. DCP Midstream, LLC has agreed to reimburse us for our share of Discovery's capital expenditures for the Tahiti pipeline lateral. The board of directors may approve additional growth capital during the year, at their discretion.

Our capital expenditures, excluding acquisitions, totaled $21.3 million and $27.2 million, including maintenance capital expenditures of $2.4 million and $2.2 million, and expansion capital expenditures of $18.9 million and $25.0 million, during 2007 and 2006, respectively. In conjunction with the acquisition of our investments in East Texas and Discovery, we entered into an agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will reimburse East Texas for 25%, and will reimburse us for 40%, of certain capital expenditures as defined in the agreement, from July 1, 2007 through completion of the capital projects, for a period not to exceed three years. In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC made capital contributions to reimburse us for certain capital projects. We also have an agreement with certain producers whereby these producers will reimburse us for certain capital projects completed by us. As a result, during the year ended December 31, 2007, we had an increase in receivables of $0.2 million and during the year ended December 31, 2006, we had a decrease in receivables of $0.4 million related to collections of maintenance capital expenditures from DCP Midstream, LLC and producers. As a result, our total maintenance capital expenditures net of reimbursements were approximately $2.6 million and $1.8 million for the years ended December 31, 2007 and 2006, respectively.

Annual maintenance capital expenditures in 2008 are expected to increase as a result of a larger asset base due to the MEG and Southern Oklahoma acquisitions. Annual expansion capital expenditures in 2008 are expected to decrease as a result of the completion of our Midland terminal in 2007. Annual expansion capital expenditures in 2007 decreased from 2006 as a result of the completion of our Wilbreeze NGL pipeline in December 2006, for which expansion capital expenditures were approximately $11.8 million, and the completion of a substantial portion of our Midland propane terminal in 2006, for which 2006 expansion capital expenditures were approximately $9.2 million. These decreases were partially offset by increased expansion capital expenditures in 2007 as a result of acquisitions. We expect to fund future capital expenditures with restricted investments, funds generated from our operations, borrowings under our credit facility and the issuance of additional partnership units.

Cash Distributions to Unitholders — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the partnership agreement. We made cash distributions to our unitholders of $43.5 million and $22.1 million during 2007 and 2006, respectively. The distributions paid during 2006 included the pro rata portion of our Minimum Quarterly Distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005. We intend to continue making quarterly distribution payments to our unitholders to the extent we have sufficient cash from operations after the establishment of reserves. We also distributed $1.0 million ($0.5 million of which is accrued) to DCP Midstream, LLC to reimburse for certain fees in connection with the 2007 acquisitions.

Description of Amended Credit Agreement — On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Amended Credit Agreement, which amended our existing Credit Agreement. This new 5-year Amended Credit Agreement consists of a $600.0 million revolving credit facility and a $250.0 million term loan facility, and matures on June 21, 2012. The amendment also improved pricing and certain other terms and conditions of the Credit Agreement. We have the option of increasing the size of the revolving credit facility to $1.0 billion with the consent of the issuing lenders. As of December 31, 2007, the outstanding balance on the revolving credit facility was $530.0 million and the outstanding balance on the term loan facility was $100.0 million.

Our obligations under the revolving credit facility are unsecured, and the term loan facility is secured at all times by high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheets, in an amount equal to or greater than the outstanding principal amount of the term loan. Any portion of the term loan balance may be repaid at any time, and we would then have access to a corresponding amount of the collateral securities. Upon any prepayment of term loan borrowings, the amount of our revolving credit facility will automatically increase to the extent that the repayment of our term loan facility is made in connection with an acquisition of assets in the midstream energy business. The unused portion of the revolving credit facility may be used for letters of credit. At December 31, 2007 and 2006, there were outstanding letters of credit of $0.2 million.

We may prepay all loans at any time without penalty, subject to the reimbursement of lender breakage costs in the case of prepayment of London Interbank Offered Rate, or LIBOR, borrowings. Indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank’s prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. As of December 31, 2007, the weighted-average interest rate on our revolving credit facility was 5.47% per annum. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank’s prime rate or the Federal Funds rate plus 0.50%. As of December 31, 2007, the interest rate on our term loan facility was 5.05%.

The Amended Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Amended Credit Agreement) exists. The Amended Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of the private placement to extinguish the $88.0 million outstanding on the Bridge Loan in June 2007.

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

A summary of our total contractual cash obligations as of December 31, 2007, is as follows:

	Payments Due by Period				
	Total	2008	2009-2010 (Millions)	2011-2012	2013 and Thereafter
Long-term debt(a)	$ 722.7	$ 23.0	$ 45.7	$ 654.0	$ —
Operating lease obligations	43.7	9.7	15.0	12.0	7.0
Purchase obligations(b)	3.2	3.2	—	—	—
Other long-term liabilities(c)	4.1	—	0.7	0.2	3.2
Total	$ 773.7	$ 35.9	$ 61.4	$ 666.2	$ 10.2

(a) Includes interest payments on long-term debt that has been hedged, because the interest rate is determinable. Interest payments on long-term debt, which has not been hedged, are not included as they are based on floating interest rates and we cannot determine with accuracy the periodic repayment dates or the amounts of the interest payments.

(b) Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized on the consolidated balance sheet. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included on the consolidated balance sheet, which represent the current fair value of various derivative contracts and do not represent future cash purchase obligations. These contracts may be settled financially at the difference between the future market price and the contractual price and may result in cash payments or cash receipts in the future, but generally do not require delivery of physical quantities of the underlying commodity. In addition, many of our gas purchase contracts include short and long term commitments to purchase produced gas at market prices. These contracts, which have no minimum quantities, are excluded from the table.

(c) Other long-term liabilities include $3.1 million of asset retirement obligations and $1.0 million of environmental reserves, recognized on the consolidated balance sheet.

Our off-balance arrangements consist solely of our operating lease obligations.

Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,"* or SFAS 160 —** In December 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

***SFAS No. 141(R) "Business Combinations (revised 2007),"* or SFAS 141(R) —** In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

***SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FAS 115*, or SFAS 159** — In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. The provisions of SFAS 159 were effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements,* or SFAS 157** — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we estimate a cumulative effect transition adjustment of an after-tax increase to partners' equity of approximately $7.3 million. This transition adjustment will directly affect the beginning balance of partners' equity. Any changes in the valuation of our trading portfolio, influenced by adjustments to our valuation assumptions, credit rating, and net open trading position, will be reflected in our results of operations in the respective period.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

***Financial Interpretation Number, or FIN, No. 48, Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement 109,* or FIN 48** — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a significant impact on our consolidated results of operations, cash flows or financial position.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

Market risk is the risk of loss arising from adverse change in market prices and rates. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of identified risks. In general, we attempt to mitigate risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements.

Risk Management Policy

We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee, which was formed effective February 8, 2006, is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. Prior to the formation of the Risk Management Committee, we were utilizing DCP Midstream, LLC's risk management policies and procedures and risk management committee to monitor and manage market risks.

We divested ourselves of all auction rate securities as of March 3, 2008.

See Note 2, Accounting for Risk Management Activities and Financial Instruments, of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for further discussion of the accounting for derivative contracts.

Credit Risk

Our principal customers in the Natural Gas Services segment are large, natural gas marketing servicers and industrial end-users. Our principal customers in the Wholesale Propane Logistics segment are primarily retail propane distributors. In the NGL Logistics Segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swaps re-price prospectively approximately every 90 days. The interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. At December 31, 2007, the effective weighted-average interest rate on our $530.0 million of outstanding revolver debt was 5.34%, taking into account the $425.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $205.0 million as of December 31, 2007, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $1.0 million annualized increase or decrease in interest expense.

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Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, and sales activities. For gathering services, we receive fees or commodities from producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, depending on the types of contracts. We employ established policies and procedures to manage our risks associated with these market fluctuations using various commodity derivatives, including forward contracts, swaps and futures.

Commodity Cash Flow Protection Activities — We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas and crude oil contracts to mitigate the effect pricing fluctuations may have on the value of our assets and operations.

We enter into derivative financial instruments to mitigate the risk of weakening natural gas, NGL and condensate prices associated with our percentage-of-proceeds arrangements and gathering operations. Because of the strong correlation between NGL prices and crude oil prices and the lack of liquidity in the NGL financial market, we typically use crude oil swaps to hedge NGL price risk. As a result of these transactions, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk through 2013.

The derivative financial instruments we have entered into are typically referred to as “swap” contracts. These swap contracts entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow protection activities. We are using the mark-to-market method of accounting for all commodity derivative instruments, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on non-trading derivative activity.

The following table sets forth additional information about our natural gas, NGL and crude oil swaps as of December 31, 2007 used to mitigate our natural gas and NGL price risk associated with our percentage-of-proceeds arrangements and our condensate price risk associated with our gathering operations:

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
January 2008 — December 2008	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2009 — December 2009	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2010 — December 2010	Natural Gas	3,900 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2008 — December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price(b)	$8.22/MMBtu
January 2008 — December 2013	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line(c)	NYMEX less $0.68/MMBtu
January 2008 — June 2008	Natural Gas	3,320 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas(d)	$6.85/MMBtu
January 2008 — June 2008	Natural Gas Liquids	14,310 gallons per day	Conway In-Line and Mt. Belvieu Non-TET(e)	$0.97/gallon
January 2008 — December 2008	Crude Oil	2,300 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2009 — December 2009	Crude Oil	2,225 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2010 — December 2010	Crude Oil	2,190 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2011 — December 2011	Crude Oil	2,125 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$66.72 - $71.35/Bbl
January 2012 — December 2012	Crude Oil	2,100 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$66.72 - $71.00/Bbl
January 2013 — December 2013	Crude Oil	1,250 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$67.60 - $71.20/Bbl

(a) The Inside FERC index price for natural gas delivered into the Texas Gas Transmission pipeline in the North Louisiana area.

(b) NYMEX final settlement price for natural gas futures contracts (NG).

(c) The Inside FERC monthly published index price for Panhandle Eastern Pipe Line (Texas, Oklahoma — mainline) less the NYMEX final settlement price for natural gas futures contracts.

(d) The Inside FERC index price for natural gas delivered into the Colorado Interstate Gas (CIG) pipeline.

(e) The average monthly OPIS price for Conway In-Line and Mt. Belvieu Non-TET.

(f) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

At December 31, 2007, the aggregate fair value of the natural gas, natural gas liquids and crude oil swaps described above was a $4.7 million net gain, a $1.6 million net loss and an $82.0 million net loss, respectively.

Subsequent to December 31, 2007, we executed a series of derivative instruments to mitigate a portion of our anticipated commodity exposure. We entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and we entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.

We estimate the following non-cash sensitivities related to the mark-to-market on our commodity derivatives associated with our Commodity Cash Flow Protection Activities:

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 6.8
NGL prices	$ 0.10	Gallon	$ 0.3
Crude oil prices	$ 5.00	Barrel	$ 19.9

We estimate the following annualized sensitivities, excluding any impact from the mark-to-market on our commodity derivatives, due to the impact of market fluctuations in 2008:

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.2
NGL prices	$ 0.10	Gallon	$ 2.8
Crude oil prices	$ 5.00	Barrel	$ 0.3

Based on our current contract mix, we believe that during 2008 we will have a long position in natural gas, NGLs and condensate, and will be sensitive to changes in commodity prices.

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which has been generally correlated to the price of crude oil. Although the prevailing price of natural gas has less short term significance to our operating results than the price of NGLs, in the long term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital, for producers to increase natural gas exploration and production. In the past, the prices of NGLs, crude oil and natural gas have been extremely volatile.

Other Asset-Based Activities — Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories.

We manage our commodity derivative activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Valuation — Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our interest rate swaps and commodity non-trading derivatives is expected to be realized in future periods, as detailed in the following table. The amount of cash ultimately realized for these contracts will differ from the amounts shown in the following table due to factors such as market volatility, counterparty default and other unforeseen events that could impact the amount and/or realization of these values.

	Fair Value of Contracts as of December 31, 2007					
Sources of Fair Value	Maturity in 2008	Maturity in 2009	Maturity in 2010	Maturity in 2011	Maturity in 2012 and Thereafter	Total Fair Value
			(Millions)			
Prices supported by quoted market prices and other external sources	$ (26.1)	$ (22.2)	$ (17.4)	$ (12.7)	$ (16.7)	$ (95.1)
Prices based on models or other valuation techniques	(1.7)	1.1	0.9	0.1	(0.4)	—
Total	$ (27.8)	$ (21.1)	$ (16.5)	$ (12.6)	$ (17.1)	$ (95.1)

The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, our New York Mercantile Exchange, or NYMEX, swap positions in natural gas, NGLs and our Asian-pricing NYMEX crude oil swaps. As of December 31, 2007, the NYMEX has quoted monthly natural gas prices for the next 72 months and quoted monthly crude oil prices for the next 71 months. In addition, this category includes our forward positions in natural gas basis swaps for which our forward price curves are obtained from Sungard Kiodex and then validated through an internal process which includes the use of independent broker quotes. On average, OTC quotes as of December 31, 2007, for natural gas basis swaps extend from 10 to 60 months into the future for the market locations at which we transact. In addition, this category includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes are available. On average, OTC quotes as of December 31, 2007, for NGLs extend one to six months into the future for the market locations at which we transact. These positions are valued against internally developed forward market price curves that are validated and recalibrated against OTC broker quotes. This category also includes “strip” transactions whose prices are obtained from external sources and then modeled to daily or monthly prices as appropriate.

The “prices based on models and other valuation methods” category includes the value of transactions for which an internally developed price curve was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

Item 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM PARTNERS, LP CONSOLIDATED FINANCIAL STATEMENTS:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream Partners GP, LLC
Denver, Colorado:

We have audited the accompanying consolidated balance sheets of DCP Midstream Partners, LP and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive (loss) income, changes in partners' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. The consolidated financial statements give retroactive effect to the acquisition of a 25% limited liability interest in DCP East Texas Holdings, LLC (formerly the East Texas Midstream Business) ("East Texas"), a 40% limited liability interest in Discovery Producer Services LLC ("Discovery"), and a nontrading derivative instrument (the "Swap") from DCP Midstream, LLC ("Midstream") by the Company on July 1, 2007, which has been accounted for in a manner similar to a pooling of interests as described in Note 4 to the consolidated financial statements. We did not audit the financial statements of Discovery, an investment of the Company which is accounted for by the use of the equity method. The Company's equity in Discovery's net assets of $161,520,000 and $162,040,000 at December 31, 2007 and 2006, respectively, and in Discovery's net income of $19,229,000, $12,033,000, and $6,909,000 for the years ended December 31, 2007, 2006 and 2005, respectively, are included in the accompanying consolidated financial statements. Discovery's financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to amounts included for Discovery, is based solely on the report of such other auditors.

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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, after giving retroactive effect to the acquisition of East Texas, Discovery, and the Swap as described in Note 4 to the consolidated financial statements, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule when considered with the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company was formed on December 7, 2005 and began operating as a separate entity. Through December 7, 2005 the accompanying consolidated financial statements have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, Midstream as a whole.

Also as described in Note 1 to the consolidated financial statements, through November 1, 2006, the portion of the accompanying consolidated financial statements attributable to the wholesale propane logistics business, have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if the wholesale propane logistics business had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

Also as described in Note 1 to the consolidated financial statements, the portion of the accompanying consolidated financial statements attributable to East Texas, Discovery and the Swap have been prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed or the results of operations if East Texas, Discovery and the Swap had been operated as unaffiliated entities. Portions of certain expenses represent allocations made from, and are applicable to Midstream as a whole.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24.5	$ 46.2
Short-term investments	1.3	0.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1.2 million and $0.3 million, respectively	81.7	43.4
Affiliates	52.1	34.8
Inventories	37.3	30.1
Unrealized gains on derivative instruments	3.1	4.2
Other	18.5	0.3
Total current assets	218.5	159.6
Restricted investments	100.5	102.0
Property, plant and equipment, net	500.7	194.7
Goodwill	80.2	29.3
Intangible assets, net	29.7	2.8
Equity method investments	187.2	170.2
Unrealized gains on derivative instruments	2.7	6.5
Other long-term assets	1.2	0.8
Total assets	$ 1,120.7	$ 665.9
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 110.2	$ 66.9
Affiliates	55.6	50.4
Unrealized losses on derivative instruments	30.9	0.7
Accrued interest payable	1.6	1.1
Other	21.3	7.4
Total current liabilities	219.6	126.5
Long-term debt	630.0	268.0
Unrealized losses on derivative instruments	70.0	2.7
Other long-term liabilities	5.8	1.0
Total liabilities	925.4	398.2
Non-controlling interests	26.9	—
Commitments and contingent liabilities		
Partners' equity:		
Predecessor equity	—	164.3
Common unitholders (16,840,326 and 10,357,143 units issued and outstanding, respectively)	308.8	223.4
Class C unitholders (0 and 200,312 units issued and outstanding, respectively)	—	(20.7)
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(120.1)	(101.6)
General partner interest	(5.4)	(5.0)
Accumulated other comprehensive (loss) income	(14.9)	7.3
Total partners' equity	168.4	267.7
Total liabilities and partners' equity	$ 1,120.7	$ 665.9

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 628.1	$ 535.1	$ 1,004.6
Sales of natural gas, propane, NGLs and condensate to affiliates	297.7	232.8	117.5
Transportation and processing services	18.5	15.0	12.5
Transportation and processing services to affiliates	16.6	12.8	10.6
Losses from derivative activity, net	(83.1)	—	—
(Losses) gains from derivative activity, net — affiliates	(4.5)	0.1	(0.9)
Total operating revenues	873.3	795.8	1,144.3
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	647.4	581.2	889.5
Purchases of natural gas, propane and NGLs from affiliates	179.3	119.2	157.8
Operating and maintenance expense	32.1	23.7	22.4
Depreciation and amortization expense	24.4	12.8	12.7
General and administrative expense	14.1	12.9	5.1
General and administrative expense — affiliates	10.0	8.1	9.1
Total operating costs and expenses	907.3	757.9	1,096.6
Operating (loss) income	(34.0)	37.9	47.7
Interest income	5.3	6.3	0.5
Interest expense	(25.8)	(11.5)	(0.8)
Earnings from equity method investments	39.3	29.2	25.7
Non-controlling interest in income	(0.5)	—	—
(Loss) income before income taxes	(15.7)	61.9	73.1
Income tax expense	(0.1)	—	(3.3)
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8
Less:			
Net income attributable to predecessor operations	(3.6)	(26.6)	(65.1)
General partner interest in net income	(2.2)	(0.7)	(0.1)
Net (loss) income allocable to limited partners	$ (21.6)	$ 34.6	$ 4.6
Net (loss) income per limited partner unit — basic and diluted	$ (1.05)	$ 1.90	$ 0.20
Weighted-average limited partner units outstanding — basic and diluted	20.5	17.5	17.5

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8
Other comprehensive (loss) income:			
Reclassification of cash flow hedges into earnings	(3.1)	(2.7)	—
Net unrealized (losses) gains on cash flow hedges	(19.1)	9.6	0.4
Total other comprehensive (loss) income	(22.2)	6.9	0.4
Total comprehensive (loss) income	$ (38.0)	$ 68.8	$ 70.2

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

	Predecessor Equity	Common Unitholders	Class C Unitholders	Subordinated Unitholders (Millions)	General Partner Interest	Accumulated Other Comprehensive (Loss) Income	Total Partners' Equity
Balance, January 1, 2005	$ 400.5	$ —	$ —	$ —	$ —	$ —	$ 400.5
Net change in parent advances	(137.7)	—	—	—	—	—	(137.7)
Proceeds from initial public offering of 10,350,000 common units	—	222.5	—	—	—	—	222.5
Underwriters' discount and offering expenses	—	(9.3)	—	(6.4)	(0.4)	—	(16.1)
Distribution to unitholders	(218.7)	—	—	—	—	—	(218.7)
Allocation of predecessor equity in exchange for 7,143 common units, 7,142,857 subordinated units and a 2% general partnership interest (represented by 357,143 equivalent units)	110.6	(0.1)	—	(105.2)	(5.3)	—	—
Net income attributable to predecessor operations	65.1	—	—	—	—	—	65.1
Net income from December 7, 2005 through December 31, 2005	—	2.7	—	1.9	0.1	—	4.7
Other comprehensive income	—	—	—	—	—	0.4	0.4
Balance, December 31, 2005	219.8	215.8	—	(109.7)	(5.6)	0.4	320.7
Net change in parent advances	(25.4)	—	—	—	—	—	(25.4)
Acquisition of wholesale propane logistics business	(56.7)	—	—	—	—	—	(56.7)
Excess purchase price over acquired assets	—	—	(26.3)	—	—	—	(26.3)
Issuance of 200,312 Class C units	—	—	5.6	—	—	—	5.6
Proceeds from general partner interest (represented by 4,088 equivalent units)	—	—	—	—	0.1	—	0.1
Contributions by unitholders	—	—	—	2.8	0.2	—	3.0
Distributions to unitholders	—	(12.8)	(0.1)	(8.8)	(0.4)	—	(22.1)
Net income attributable to predecessor operations	26.6	—	—	—	—	—	26.6
Net income	—	20.4	0.1	14.1	0.7	—	35.3
Other comprehensive income	—	—	—	—	—	6.9	6.9
Balance, December 31, 2006	164.3	223.4	(20.7)	(101.6)	(5.0)	7.3	267.7
Net change in parent advances	(14.6)	—	—	—	—	—	(14.6)
Acquisition of East Texas, Discovery and the Swap	(153.3)	27.0	—	—	0.6	—	(125.7)
Excess purchase price over acquired assets	—	(118.0)	—	—	—	—	(118.0)
Acquisition of Momentum Energy Group, Inc.	—	12.0	—	—	—	—	12.0
Purchase of units	—	(0.3)	—	—	—	—	(0.3)
Issuance of units	—	0.3	—	—	—	—	0.3
Issuance of 5,386,732 common units	—	228.5	—	—	—	—	228.5
Conversion of Class C units to common units	—	(20.7)	20.7	—	—	—	—
Contributions by unitholders	—	0.2	—	0.6	—	—	0.8
Distributions to unitholders	—	(27.0)	(0.2)	(14.1)	(3.2)	—	(44.5)
Equity-based compensation	—	0.2	—	—	—	—	0.2
Net income attributable to predecessor operations	3.6	—	—	—	—	—	3.6
Net income (loss)	—	(16.8)	0.2	(5.0)	2.2	—	(19.4)
Other comprehensive loss	—	—	—	—	—	(22.2)	(22.2)
Balance, December 31, 2007	$ —	$ 308.8	$ —	$ (120.1)	$ (5.4)	$ (14.9)	$ 168.4

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	2006	2005
		(Millions)	
OPERATING ACTIVITIES:			
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation and amortization expense	24.4	12.8	12.7
Earnings from equity method investments, net of distributions	(0.4)	(3.3)	11.0
Non-controlling interest in income	0.5	—	—
Deferred income tax benefit	—	—	(0.5)
Other, net	(0.2)	(2.4)	0.1
Change in operating assets and liabilities which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	(42.2)	43.1	(30.7)
Inventories	(7.2)	11.6	(21.0)
Net unrealized losses (gains) on derivative instruments	81.1	(0.1)	0.1
Accounts payable	38.9	(31.5)	74.7
Accrued interest	0.5	0.3	0.8
Income tax payable	—	—	(3.2)
Other current assets and liabilities	(16.4)	2.0	(0.7)
Other long-term assets and liabilities	2.2	0.4	(0.1)
Net cash provided by operating activities	65.4	94.8	113.0
INVESTING ACTIVITIES:			
Capital expenditures	(21.3)	(27.2)	(10.8)
Acquisition of subsidiaries of Momentum Energy Group, Inc., net of cash acquired	(142.0)	—	—
Acquisition of assets	(191.3)	—	—
Acquisition of equity method investments	(153.3)	—	—
Investments in equity method investments	(16.3)	(11.1)	(20.5)
Payment of earnest deposit	(9.0)	—	—
Refund of earnest deposit	9.0	—	—
Acquisition of wholesale propane logistics business	—	(56.7)	—
Proceeds from sales of assets	0.1	0.3	1.2
Purchases of available-for-sale securities	(6,921.6)	(7,372.4)	(731.0)
Proceeds from sales of available-for-sale securities	6,924.0	7,373.3	630.8
Other investing activities	—	—	(0.1)
Net cash used in investing activities	(521.7)	(93.8)	(130.4)
FINANCING ACTIVITIES:			
Borrowings of debt	579.0	78.0	210.1
Repayments of debt	(217.0)	(20.1)	—
Payment of deferred financing costs	(0.6)	(0.2)	(0.5)
Purchase of units	(0.3)	—	—
Proceeds from issuance of common units, net of offering costs	228.5	—	206.4
Proceeds from issuance of equivalent units to general partner	—	0.1	—
Excess purchase price over acquired assets	(100.3)	(10.7)	—
Net change in advances from DCP Midstream, LLC	(14.6)	(25.4)	(137.7)
Distributions to unitholders	(44.0)	(22.1)	(218.7)
Contributions from non-controlling interests	3.4	—	—
Contributions from DCP Midstream, LLC	0.5	3.4	—
Net cash provided by financing activities	434.6	3.0	59.6
Net change in cash and cash equivalents	(21.7)	4.0	42.2
Cash and cash equivalents, beginning of period	46.2	42.2	—
Cash and cash equivalents, end of period	$ 24.5	$ 46.2	$ 42.2

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2007, 2006 and 2005

1. Description of Business and Basis of Presentation

DCP Midstream Partners, LP, with its consolidated subsidiaries, or us, we or our, is engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas, producing, transporting, storing and selling propane and transporting and selling NGLs and condensate.

We are a Delaware master limited partnership that was formed in August 2005. We completed our initial public offering on December 7, 2005. Our partnership includes: our Northern Louisiana system; our Southern Oklahoma system (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our wholesale propane logistics business (acquired in November 2006); and our NGL transportation pipelines.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to us and operate our assets. DCP Midstream, LLC owns approximately 35% of our partnership.

The consolidated financial statements include our accounts, and prior to December 7, 2005 the assets, liabilities and operations contributed to us by DCP Midstream, LLC and its wholly-owned subsidiaries, which we refer to as DCP Midstream Partners Predecessor, upon the closing of our initial public offering, which have been combined with the historical assets, liabilities and operations of our wholesale propane logistics business which we acquired from DCP Midstream, LLC in November 2006, and our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and a non-trading derivative instrument, or the Swap, which DCP Midstream, LLC entered into in March 2007, which we acquired from DCP Midstream, LLC in July 2007. These were transactions among entities under common control. We recognize transfers of net assets between entities under common control at DCP Midstream, LLC's basis in the net assets contributed. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method; accordingly, our financial information includes the historical results of our wholesale propane logistics business, Discovery and East Texas for all periods presented. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. In addition, the results of operations of Momentum Energy Group Inc., or MEG, have been included in the consolidated financial statements since the date of acquisition.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. We refer to DCP Midstream Partners Predecessor, the assets, liabilities and operations of our wholesale propane logistics business, our equity interests in East Texas and Discovery, and the Swap, prior to our acquisition from DCP Midstream, LLC, collectively as our "predecessors." The consolidated financial statements of our predecessors have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations have been identified in the consolidated financial statements as transactions between affiliates.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents — We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less to be cash equivalents.

Short-Term and Restricted Investments — We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments are used as collateral to secure the term loan portion of our credit facility and to finance gathering and compression asset acquisitions.

We have classified all short-term and restricted investments as available-for-sale as we do not intend to hold them to maturity, nor are they bought or sold with the objective of generating profit on short-term differences in prices. These investments are recorded at fair value, with changes in fair value recorded as unrealized gains and losses in accumulated other comprehensive (loss) income, or AOCI. The cost, including accrued interest on investments, approximates fair value, due to the short-term, highly liquid nature of the securities held by us, and as interest rates are re-set on a daily, weekly or monthly basis.

Inventories — Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Goodwill and Intangible Assets — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

Intangible assets consist primarily of commodity purchase contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit, ranging from approximately two to 25 years.

Long-Lived Assets — We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Equity Method Investments — We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Unamortized Debt Expense — Expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. These expenses are recorded on the consolidated balance sheet as other long-term assets.

Non-Controlling Interest — Non-controlling interest represents the non-controlling interest holders ownership interests in the net assets of Collbran Valley Gas Gathering, a joint venture acquired in conjunction with the MEG acquisition in August 2007. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party investors.

Accounting for Risk Management Activities and Financial Instruments — Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow protection activities. We are using the mark-to-market method of accounting for all commodity derivative instruments beginning in July 2007. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings.

All derivative activity reflected in the consolidated financial statements for our predecessors was transacted by us or by DCP Midstream, LLC and its subsidiaries, and transferred and/or allocated to us. All derivative activity reflected in the consolidated financial statements, which is not related to our predecessors, has been and will be transacted by us. Prior to July 1, 2007, we designated each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives were further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading derivative activity. For the periods presented, we did not have any trading derivative activity, however, we did have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in the consolidated financial statements. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Non-Trading Derivative Activity	Mark-to-market method(b)	Net basis in gains and losses from derivative activity
Cash Flow Hedge(a)	Hedge method(c)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge(a)	Hedge method(c)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method(d)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale

(a) Effective July 1, 2007, all commodity cash flow hedges are classified as non-trading derivative activity. Our interest rate swaps continue to be accounted for as cash flow hedges. As of December 31, 2007 we no longer use fair value hedges.

(b) Mark-to-market — An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in gains and losses from derivative activity during the current period.

(c) Hedge method — An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the change in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.

(d) Accrual method — An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges — For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners' equity as AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

Valuation — When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Revenue Recognition — We generate the majority of our revenues from gathering, processing, compressing, transporting, and fractionating natural gas and NGLs, and from trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

- *Fee-based arrangements* — Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing or transporting natural gas; and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.
- *Percentage-of-proceeds/index arrangements* — Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percentage-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.
- *Propane sales arrangements* — Under propane sales arrangements, we generally purchase propane from natural gas processing plants and fractionation facilities, and crude oil refineries. We sell propane on a wholesale basis to retail propane distributors, who in turn resell to their retail customers. Our sales of propane are not contingent upon the resale of propane by propane distributors to their retail customers.

Our marketing of natural gas and NGLs consists of physical purchases and sales, as well as positions in derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract, executed by both us and the customer.
- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.
- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectibility is probable* — Collectibility is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers’ financial position (for example, cash position and credit rating) and their ability to pay. If collectibility is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the fee is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody to the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for non-trading derivative activity net in the consolidated statements of operations as gains and losses from derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the financial or physical settlement of energy trading contracts.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable — trade and accounts receivable — affiliates were imbalances of $1.6 million and $0.1 million at December 31, 2007 and 2006, respectively. Included in the consolidated balance sheets as accounts payable — trade were imbalances of $1.1 million and $0.9 million at December 31, 2007 and 2006, respectively.

Significant Customer — There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2007 and 2006. We had one third party customer that accounted for 17% of total operating revenues for the year ended December 31, 2005. Revenues from this customer are reported in the NGL Logistics Segment. We also had significant transactions with affiliates, and with suppliers of natural gas and propane (see "Item 1. Business — Natural Gas Services Segment" and "— Wholesale Propane Logistics Segment," respectively)

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of December 31, 2007, included in the consolidated balance sheets as other current liabilities amounted to $0.7 million and as other long-term liabilities amounted to $1.0 million. Environmental liabilities as of December 31, 2006 were not significant.

Equity-Based Compensation — Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Income Taxes — We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our wholesale propane logistics business changed its tax structure, effective December 7, 2005, such that it became a pass-through entity. Prior to December 7, 2005, our wholesale propane logistics business was considered taxable for United States income tax purposes. Our wholesale propane logistics business followed the asset and liability method of accounting for income taxes, whereby deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Subsequent to December 7, 2005, our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is includable in the federal returns of each partner.

Comprehensive (Loss) Income — Comprehensive (loss) income consists of net income or loss and other comprehensive income or loss, which includes unrealized gains and losses on the effective portion of derivative instruments classified as cash flow hedges.

Net Income per Limited Partner Unit — Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions, by the weighted-average number of outstanding limited partner units during the period.

3. Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,"* or SFAS 160 —** In December 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

***SFAS No. 141(R) "Business Combinations (revised 2007),"* or SFAS 141(R) —** In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

***SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FAS 115*, or SFAS 159** — In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. The provisions of SFAS 159 were effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements*, or SFAS 157** — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we estimate a cumulative effect transition adjustment of an after-tax increase to partners' equity of approximately $7.3 million. This transition adjustment will directly affect the beginning balance of partners' equity.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While, we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

***FASB Interpretation Number, or FIN, No. 48, Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement 109,* or FIN 48** — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a significant impact on our consolidated results of operations, cash flows or financial position.

4. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of MEG from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of revolver and term loan borrowings under our amended credit agreement, along with the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the Securities and Exchange Commission, or SEC, in January 2008.

The transfer of the MEG subsidiaries between DCP Midstream, LLC and us represents a transfer between entities under common control. Transfers between entities under common control are accounted for at DCP Midstream, LLC's carrying value, similar to the pooling method. DCP Midstream, LLC recorded its acquisition of the MEG subsidiaries under the purchase method of accounting, whereby the assets and liabilities were recorded at their respective fair values as of the date of the acquisition, including goodwill of approximately $50.9 million. The goodwill amount recognized relates primarily to projected growth in the Piceance basin due to significant natural gas reserves and high levels of drilling activity. We expect all of the goodwill to be tax deductible. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained. When finalized, material adjustments to goodwill may result. The purchase price allocation is as follows:

	(Millions)
Cash consideration	$ 153.8
Payable to DCP Midstream, LLC	9.0
Common limited partner units	12.0
Aggregate consideration	$ 174.8
The purchase price allocation is as follows:	
Cash	$ 11.8
Accounts receivable	14.1
Other assets	1.5
Property, plant and equipment	123.5
Goodwill	50.9
Intangible assets	15.5
Accounts payable	(11.1)
Other liabilities	(8.6)
Non-controlling interest in joint venture	(22.8)
Total purchase price allocation	$ 174.8

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC, in a transaction among entities under common control, for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including net working capital of $1.3 million and other adjustments, the issuance of 620,404 common units to DCP Midstream, LLC valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings of $245.9 million under our amended credit facility. The $118.0 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners' equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners' equity. The transfer of assets between DCP Midstream, LLC and us represents a transfer of assets between entities under common control. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method.

In May 2007, we acquired certain gathering and compression assets located in southern Oklahoma, or the Southern Oklahoma system, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181.1 million.

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million.

The results of operations for the MEG subsidiaries, and the Southern Oklahoma and northern Louisiana acquired assets, have been included prospectively, from the dates of acquisition, as part of the Natural Gas Services segment.

Wholesale Propane Logistics Business

On November 1, 2006, we acquired our wholesale propane logistics business from DCP Midstream, LLC, in a transaction among entities under common control, for aggregate consideration of approximately $82.9 million, which consisted of $77.3 million in cash ($9.9 million of which was paid in January 2007), and the issuance of 200,312 Class C units valued at approximately $5.6 million. Included in the aggregate consideration was $10.5 million of costs incurred through October 31, 2006, which were associated with the construction of a new pipeline terminal. The $26.3 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners' equity, and the $5.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners' equity.

Combined Financial Information

The following table presents the impact to the consolidated balance sheet, adjusted for the acquisition of East Texas and Discovery, from DCP Midstream, LLC. The Swap was entered into by DCP Midstream, LLC in March 2007, and therefore it is not included below.

As of December 31, 2006

	DCP Midstream Partners, LP	East Texas and Discovery	Combined DCP Midstream Partners, LP
ASSETS			
Current assets:			
Cash and cash equivalents	$ 46.2	$ —	$ 46.2
Accounts receivable	78.2	—	78.2
Inventories	30.1	—	30.1
Other	5.1	—	5.1
Total current assets	159.6	—	159.6
Restricted investments	102.0	—	102.0
Property, plant and equipment, net	194.7	—	194.7
Goodwill and intangible assets, net	32.1	—	32.1
Other non-current assets	13.2	164.3	177.5
Total assets	$ 501.6	$ 164.3	$ 665.9
LIABILITIES AND PARTNERS' EQUITY			
Accounts payable and other current liabilities	$ 126.5	$ —	$ 126.5
Long-term debt	268.0	—	268.0
Other long-term liabilities	3.7	—	3.7
Total liabilities	398.2	—	398.2
Commitments and contingent liabilities			
Partners' equity:			
Net equity	96.1	164.3	260.4
Accumulated other comprehensive income	7.3	—	7.3
Total partners' equity	103.4	164.3	267.7
Total liabilities and partners' equity	$ 501.6	$ 164.3	$ 665.9

The following tables present the impact to the consolidated statements of operations, adjusted for the acquisition of our wholesale propane logistics business, and for the acquisition of East Texas and Discovery from DCP Midstream, LLC, for the periods indicated. The Swap was entered into by DCP Midstream, LLC in March 2007, and therefore it is not included below.

Year Ended December 31, 2006

	DCP Midstream Partners, LP and Predecessor	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 767.9	$ —	$ 767.9
Transportation and other	27.9	—	27.9
Total operating revenues	795.8	—	795.8
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	700.4	—	700.4
Operating and maintenance expense	23.7	—	23.7
Depreciation and amortization expense	12.8	—	12.8
General and administrative expense	21.0	—	21.0
Total operating costs and expenses	757.9	—	757.9
Operating income	37.9	—	37.9
Interest expense, net	(5.2)	—	(5.2)
Earnings from equity method investments	0.3	28.9	29.2
Income tax expense	—	—	—
Net income	$ 33.0	$ 28.9	$ 61.9

Year Ended December 31, 2005

	DCP Midstream Partners, LP and Predecessor	Wholesale Propane Logistics Business	East Texas and Discovery	Combined DCP Midstream Partners, LP
Operating revenues:				
Sales of natural gas, propane, NGLs and condensate	$ 762.3	$ 359.8	$ —	$ 1,122.1
Transportation and other	22.2	—	—	22.2
Total operating revenues	784.5	359.8	—	1,144.3
Operating costs and expenses:				
Purchases of natural gas, propane and NGLs	709.3	338.0	—	1,047.3
Operating and maintenance expense	14.2	8.2	—	22.4
Depreciation and amortization expense	11.7	1.0	—	12.7
General and administrative expense	11.4	2.8	—	14.2
Total operating costs and expenses	746.6	350.0	—	1,096.6
Operating income	37.9	9.8	—	47.7
Interest expense, net	(0.3)	—	—	(0.3)
Earnings from equity method investments	0.4	—	25.3	25.7
Income tax expense	—	(3.3)	—	(3.3)
Net income	$ 38.0	$ 6.5	$ 25.3	$ 69.8

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

DCP Midstream, LLC provided centralized corporate functions on behalf of our predecessor operations, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The predecessor's share of those costs was allocated based on the predecessor's proportionate net investment (consisting of property, plant and equipment, net, equity method investments, and intangible assets, net) as compared to DCP Midstream, LLC's net investment. In management's estimation, the allocation methodologies used were reasonable and resulted in an allocation to the predecessors of their respective costs of doing business, which were borne by DCP Midstream, LLC.

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering.

All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

The Omnibus Agreement also addresses the following matters:

- DCP Midstream, LLC's obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of the closing of our initial public offering in December 2005, until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody's Investor Services, Inc. or Standard & Poor's Ratings Group with respect to any of our unsecured indebtedness; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if the general partner is removed without cause and units held by the general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us, the general partner (DCP Midstream GP, LP) or the General Partner (DCP Midstream GP, LLC).

Following is a summary of the fees we incurred in 2007 under the Omnibus Agreement and the effective date for these fees, as well as other fees paid to DCP Midstream, LLC:

Terms	Effective Date	Year Ended December 31, 2007	2006	2005
			(Millions)	
Annual fee	2006	$ 5.0	$ 4.8	$ 0.3
Wholesale propane logistics business	November 2006	2.0	0.3	—
Southern Oklahoma	May 2007	0.1	—	—
Discovery	July 2007	0.1	—	—
Additional services	August 2007	0.2	—	—
MEG	August 2007	0.5	—	—
Total Omnibus Agreement		7.9	5.1	0.3
Other fees		2.1	3.0	8.8
Total		$ 10.0	$ 8.1	$ 9.1

Competition

None of DCP Midstream, LLC, nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either the partnership agreement or the Omnibus Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify us until December 7, 2008 against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DCP Midstream, LLC's maximum liability for this indemnification obligation does not exceed $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including pre-closing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the post-closing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC's indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake Pipe Line Company, or Black Lake, associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through June 2008. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Reimbursements of these expenses from DCP Midstream, LLC were not significant and were recognized by us as capital contributions.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC will indemnify us until October 31, 2008 for any breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, DCP Midstream, LLC agreed to indemnify us until October 31, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until October 31, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing, agreed to indemnify us until October 31, 2010 if certain contractual matters result in a claim, and agreed to indemnify us indefinitely for breaches of the agreement. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $680,000 and is subject to a maximum liability of $6.8 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, DCP Midstream, LLC will indemnify us until July 1, 2008 for the breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us until July 1, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until July 1, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels, and agreed to indemnify us indefinitely for breaches of the agreement and certain existing claims. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisition of certain subsidiaries of MEG, DCP Midstream will indemnify us following the closing on August 29, 2007 for any breach of the representations and warranties made under the acquisition agreement and certain other matters associated with these assets. DCP Midstream agreed to indemnify us until August 29, 2008 for any breach of the representations and warranties (except certain corporate related matters that survive indefinitely), and indefinitely for breaches of the agreement.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to the inlet of the Pelico system, and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. Because of DCP Midstream, LLC's ability to move natural gas around Pelico, there are certain contractual relationships around Pelico that define how natural gas is bought and sold between us and DCP Midstream, LLC. The agreement is described below:

- DCP Midstream, LLC will supply Pelico's system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. We generally report purchases associated with these activities gross in the consolidated statements of operations as purchases of natural gas, propane and NGLs from affiliates.
- If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price, less a

contractually agreed-to marketing fee. We generally report revenues associated with these activities gross in the consolidated statements of operations as sales of natural gas, propane and NGLs to affiliates.

- In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC, plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential, plus a fixed fuel charge and other related adjustments. We generally report revenues and purchases associated with these activities net in the consolidated statements of operations as transportation and processing services to affiliates.

In addition, we sell NGLs and condensate from our Minden and Ada processing plants, and condensate from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation and other charges from the tailgate of the respective asset, which is recorded in the consolidated statements of operations as sales of natural gas, propane, NGLs and condensate to affiliates. We also sell propane to a subsidiary of DCP Midstream, LLC.

We also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze pipeline, pursuant to a fee-based rate that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a transportation agreement. We generally report revenues associated with these activities in the consolidated statements of operations as transportation and processing services to affiliates.

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by an NGL product dedication agreement with DCP Midstream, LLC. We generally report revenues, which are earned pursuant to a fee-based rate applied to the volumes transported on this pipeline, in the consolidated statements of operations as transportation and processing services to affiliates.

We anticipate continuing to purchase commodities from and sell commodities to DCP Midstream, LLC in the ordinary course of business.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.4 million during 2006 and $0.3 million during 2007, to reimburse us for the capital costs we incurred, primarily for growth capital projects.

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $0.3 million during 2007, to reimburse us for these capital projects. As of December 31, 2007, $0.1 million of the capital contributions are included in accounts receivable — affiliates in the consolidated balance sheets.

We had an operating lease with an affiliate during the year ended December 31, 2005. Operating lease expense related to this lease was $0.7 million for the year ended December 31, 2005.

DCP Midstream, LLC was a significant customer during the years ended December 31, 2007, 2006 and 2005.

Duke Energy

Prior to December 31, 2006, we charged transportation fees, sold a portion of our residue gas to, and purchased raw natural gas from, Duke Energy and its affiliates.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $2.9 million, $3.9 million and $0.2 million of capital reimbursements during the years ended December 31, 2007, 2006 and 2005, respectively.

The following table summarizes the transactions with affiliates:

	Year Ended December 31,		
	2007	2006	2005
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 290.0	$ 231.7	$ 108.8
Transportation and processing services	$ 6.0	$ 4.8	$ 0.3
Purchases of natural gas, propane and NGLs	$ 150.1	$ 102.9	$ 134.4
(Losses) gains from derivative activity, net	$ (4.5)	$ 0.1	$ (0.9)
Operating and maintenance expense	$ 0.4	$ 0.2	$ —
General and administrative expense	$ 10.0	$ 8.1	$ 9.1
Spectra Energy:			
Sales of natural gas, propane, NGLs and condensate	$ 1.1	$ —	$ —
Duke Energy:			
Sales of natural gas, propane, NGLs and condensate	$ —	$ —	$ 1.4
Transportation and processing services	$ —	$ —	$ 0.3
Purchases of natural gas, propane and NGLs	$ —	$ 3.4	$ 4.7
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ 6.6	$ 1.1	$ 7.3
Transportation and processing services	$ 10.6	$ 8.0	$ 10.0
Purchases of natural gas, propane and NGLs	$ 29.2	$ 12.9	$ 18.7

We had accounts receivable and accounts payable with affiliates as follows:

	December 31, 2007	December 31, 2006
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 47.3	$ 30.0
Accounts payable	$ 53.3	$ 46.6
Spectra Energy:		
Accounts receivable	$ 1.5	$ —
Duke Energy:		
Accounts receivable	$ —	$ 0.2
Accounts payable	$ —	$ 1.8
ConocoPhillips:		
Accounts receivable	$ 3.3	$ 4.6
Accounts payable	$ 2.3	$ 2.0

The following summarizes the unrealized gains and unrealized losses on derivative instruments with affiliates:

	December 31, 2007	December 31, 2006
	(Millions)	
DCP Midstream, LLC:		
Unrealized gains — current	$ —	$ 0.3
Unrealized losses — current	$ (2.7)	$ (0.2)

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2007	December 31, 2006
		(Millions)	
Gathering systems	15 — 30 Years	$ 371.3	$ 107.3
Processing plants	25 — 30 Years	91.4	53.2
Terminals	25 — 30 Years	24.2	8.2
Transportation	25 — 30 Years	141.0	139.6
General plant	3 — 5 Years	4.0	3.6
Construction work in progress		25.5	16.2
Property, plant and equipment		657.4	328.1
Accumulated depreciation		(156.7)	(133.4)
Property, plant and equipment, net		$ 500.7	$ 194.7

The above amounts include accrued capital expenditures of $8.4 million and $1.9 million as of December 31, 2007 and 2006, respectively, which are included in other current liabilities in the consolidated balance sheets.

Depreciation expense was $23.3 million, $12.4 million and $12.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Asset Retirement Obligations — Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation, included in other long-term liabilities in the consolidated balance sheets, was $3.1 million and $0.5 million at December 31, 2007 and 2006, respectively. The asset retirement obligation increased in 2007 as a result of the MEG acquisition. Accretion expense for the year ended December 31, 2007 was $0.1 million and for the years ended December 31, 2006 and 2005 was not significant.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31, 2007	December 31, 2006
	(Millions)	
Beginning of period	$ 29.3	$ 29.3
Acquisitions	50.9	—
End of period	$ 80.2	$ 29.3

Goodwill of $29.3 million represents the amount that was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in our Wholesale Propane Logistics segment, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired in November 2006. The increase in goodwill during 2007 of $50.9 million represents the amount that we recognized in connection with our acquisition of the MEG subsidiaries from DCP Midstream, LLC.

We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment tests indicated that our reporting unit's fair value exceeded its carrying or book value; therefore, we did not record any impairment charges during the years ended December 31, 2007, 2006 and 2005.

Intangible assets consist primarily of commodity purchase contracts and relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2007	December 31, 2006
	(Millions)	
Gross carrying amount	$ 32.4	$ 4.4
Accumulated amortization	(2.7)	(1.6)
Intangible assets, net	$ 29.7	$ 2.8

Intangible assets increased as a result of the Southern Oklahoma and MEG acquisitions, through which $12.5 million and $15.5 million, respectively, of intangible assets were acquired.

One customer has notified us that they intend to exercise their early termination right prior to the end of the contract term. Accordingly, we are not amortizing the estimated termination fee of $0.5 million, which is included in intangible assets in the above table as of December 31, 2007 and 2006.

For the years ended December 31, 2007, 2006 and 2005, we recorded amortization expense of $1.1 million, $0.4 million and $0.7 million, respectively. As of December 31, 2007, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 20 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (Millions)
2008	$ 1.8
2009	1.6
2010	1.5
2011	1.5
2012	1.5
Thereafter	21.3
Total	$ 29.2

8. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of December 31, 2007 and 2006	Carrying Value as of December 31, 2007	Carrying Value as of December 31, 2006
		(Millions)	
Discovery Producer Services LLC	40%	$ 117.9	$ 113.4
DCP East Texas Holdings, LLC	25%	62.9	50.9
Black Lake Pipe Line Company	45%	6.2	5.7
Other	50%	0.2	0.2
Total equity method investments		$ 187.2	$ 170.2

Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to its processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 280 miles of pipe, and several laterals in the Gulf of Mexico. There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $43.7 million and $48.6 million at December 31, 2007 and 2006, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and NGLs. Its operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 MMcf/d and a natural gas liquids fractionator. The facility is connected to an approximately 845-mile gathering system, as well as third party gathering systems. The complex includes and is adjacent to the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 Bcf/d, acts as a key exchange point for the purchase and sale of residue gas.

Black Lake owns a 317-mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.4 million and $6.7 million at December 31, 2007 and 2006, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Prior to December 7, 2005, DCP Midstream Partners Predecessor held a 50% interest in Black Lake. Upon completion of our initial public offering, DCP Midstream, LLC retained a 5% interest in Black Lake.

Earnings from equity method investments were as follows:

	Year Ended December 31,		
	2007	2006 (Millions)	2005
Discovery Producer Services LLC	$ 24.1	$ 16.9	$ 10.8
DCP East Texas Holdings, LLC	14.6	12.0	14.5
Black Lake Pipe Line Company and other	0.6	0.3	0.4
Total earnings from equity method investments	$ 39.3	$ 29.2	$ 25.7
Distributions from equity method investments	$ 38.9	$ 25.9	$ 36.7
Earnings from equity method investments, net of distributions	$ 0.4	$ 3.3	$ (11.0)

The following summarizes financial information of our equity method investments:

	Year Ended December 31,		
	2007	2006 (Millions)	2005
Statements of operations:			
Operating revenue	$ 739.6	$ 686.9	$ 672.1
Operating expenses	$ 634.6	$ 612.2	$ 594.8
Net income	$ 106.8	$ 77.4	$ 77.9

	December 31, 2007	December 31, 2006
	(Millions)	
Balance sheet:		
Current assets	$ 168.8	$ 108.9
Long-term assets	630.3	630.7
Current liabilities	100.9	94.8
Long-term liabilities	14.9	6.0
Net assets	$ 683.3	$ 638.8

9. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts. The following summarizes the estimated fair value of financial instruments:

	December 31, 2007		December 31, 2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Millions)			
Restricted investments	$ 100.5	$ 100.5	$ 102.0	$ 102.0
Accounts receivable	$ 133.8	$ 133.8	$ 78.2	$ 78.2
Accounts payable	$ 165.8	$ 165.8	$ 117.3	$ 117.3
Net unrealized (losses) gains on derivative instruments	$ (95.1)	$ (95.1)	$ 7.3	$ 7.3
Long-term debt	$ 630.0	$ 630.0	$ 268.0	$ 268.0

The fair value of restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value.

The carrying value of long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

10. Debt

Long-term debt was as follows:

	Principal Amount 2007	2006
	(Millions)	
Revolving credit facility, weighed-average interest rate of 5.47% and 5.86%, respectively, due June 21, 2012	$ 530.0	$ 168.0
Term loan facility, interest rate of 5.05% and 5.47%, respectively, due June 21, 2012	100.0	100.0
Total long-term debt	$ 630.0	$ 268.0

Credit Agreements

On June 21, 2007, we entered into the Amended and Restated Credit Agreement, or the Amended Credit Agreement, that replaced our existing credit agreement, or the Credit Agreement, which consists of:

- a $600.0 million revolving credit facility; and
- a $250.0 million term loan facility.

At December 31, 2007 and 2006, we had $0.2 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2007 and 2006. We have incurred $0.6 million of debt issuance costs associated with the Amended Credit Agreement. These expenses are deferred as other long-term assets in the consolidated balance sheet and will be amortized over the term of the Amended Credit Agreement.

Under the Amended Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank’s prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank’s prime rate or the Federal Funds rate plus 0.50%.

The Amended Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88.0 million outstanding on the Bridge Loan in June 2007.

11. Partnership Equity and Distributions

General — Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

In November 2007, our universal shelf registration statement on Form S-3 was declared effective by the SEC. The universal shelf registration statement has a maximum aggregate offering price of $1.5 billion, which will allow us to register and issue additional partnership units and debt obligations.

In June 2007, we entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs.

In July 2007, we issued 620,404 common units to DCP Midstream, LLC as partial consideration for the purchase of Discovery, East Texas and the Swap. In August 2007, we issued 275,735 common units to DCP Midstream, LLC as partial consideration for the purchase of certain subsidiaries of MEG.

In August 2007, we issued 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate.

In January 2008, our registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

Definition of Available Cash — Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to the unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights — Prior to June 2007, the general partner was entitled to 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner did not participate in certain issuances of common units during 2007. Therefore, the general partner's 2% interest was reduced to 1.5%.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights were not reduced as a result of these private placement agreements, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Class C Units — On July 2, 2007, the Class C units were converted to common units.

Subordinated Units — All of the subordinated units are held by DCP Midstream, LLC. Our partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. We determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and, therefore, 50% of the subordinated units converted into common units. Our board of directors and the conflicts committee of the board certified that all conditions for early conversion were satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period — Our partnership agreement, after adjustment for the general partner's relative ownership level, currently 1.5%, requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

- *first*, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, to the common unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, to the subordinated unitholders and the general partner, in accordance with their pro rata interest, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);
- *fifth*, 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);
- *sixth*, 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period — Our partnership agreement, after adjustment for the general partner's relative ownership level, requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, to all unitholders and the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second*, 13% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third*, 23% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter*, 48% to the general partner, plus the general partner's pro rata interest, and the remainder to all unitholders.

The following table presents our cash distributions paid in 2007 and 2006:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2007	$ 0.550	$ 14.7
August 14, 2007	0.530	12.4
May 15, 2007	0.465	8.6
February 14, 2007	0.430	7.8
November 14, 2006	0.405	7.4
August 14, 2006	0.380	6.7
May 15, 2006	0.350	6.3
February 13, 2006(a)	0.095	1.7

(a) Represents the pro rata portion of our Minimum Quarterly distribution of $0.35 per unit for the period December 7, 2005, the closing of our initial public offering, through December 31, 2005.

12. Risk Management Activities, Credit Risk and Financial Instruments

The impact of our derivative activity on our results of operations and financial position is summarized below:

	Year Ended December 31, 2007	2006 (Millions)	2005
Commodity cash flow hedges:			
Losses due to ineffectiveness	$ —	$ (0.3)	$ 0.3
Gains reclassified into earnings	$ 2.4	$ 2.6	$ —
Commodity derivative activity:			
Unrealized (losses) gains from derivative activity	$ (81.7)	$ 0.3	$ (0.4)
Realized losses from derivative activity	$ (5.9)	$ (0.2)	$ (0.5)
Interest rate cash flow hedges:			
Gains reclassified into earnings	$ 0.7	$ 0.1	$ —

	December 31, 2007	December 31, 2006
	(Millions)	
Commodity cash flow hedges:		
Net deferred (losses) gains in AOCI	$ (2.6)	$ 6.9
Interest rate cash flow hedges:		
Net deferred (losses) gains in AOCI	$ (12.3)	$ 0.4

For the years ended December 31, 2007, 2006 and 2005, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of the identified risks. In general, we attempt to mitigate risks related to the variability of future cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. We have established a comprehensive risk management policy, or the Risk Management Policy, and a risk management committee, to monitor and manage market risks associated with commodity prices and interest rates. Our Risk Management Policy prohibits the use of derivative instruments for speculative purposes.

As of December 31, 2007, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $18.2 million, which is included in other current assets on the consolidated balance sheet.

Commodity Price Risk — Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. The amount and type of price risk is dependent on the mechanisms and locations for purchases, sales, transportation and storage of propane.

We manage our commodity derivative activities in accordance with our Risk Management Policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Interest Rate Risk — Interest rates on credit facility balances and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Credit Risk — In the Natural Gas Services segment, we sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. In the Wholesale Propane Logistics segment, we sell primarily to retail propane distributors. In the NGL Logistics segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy and guidelines. The agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Commodity Cash Flow Protection Activities — We used NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statements of operations in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. Deferred net losses of $0.8 million are expected to be reclassified during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in gains and losses from derivative activity in the consolidated statements of operations.

As of December 31, 2007, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas, NGLs and crude oil derivatives.

Other Asset-Based Activity — To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price variability across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Commodity Fair Value Hedges — Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our cash flow exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Interest Rate Cash Flow Hedges — We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets. As of December 31, 2007, $3.0 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

13. Equity-Based Compensation

Total compensation cost for equity-based arrangements was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Performance Units	$ 1.1	$ 0.2	$ —
Phantom Units	0.6	0.4	—
Total compensation cost	$ 1.7	$ 0.6	$ —

On November 28, 2005, the board of directors of our General Partner adopted a long-term incentive plan, or LTIP, for employees, consultants and directors of our General Partner and its affiliates who perform services for us, effective as of December 7, 2005. Under the LTIP, equity-based instruments may be granted to our key employees. The LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner's tax withholding obligations, are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner's board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Awards granted to directors are accounted for as equity-based awards and all other awards are accounted for as liability awards.

Performance Units — We have awarded phantom LPUs, or Performance Units, pursuant to the LTIP to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units that will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the compensation committee of the board of directors of our General Partner. The DERs will be paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2007, 28,350 units are expected to vest on December 31, 2008 and 27,150 units are expected to vest on December 31, 2009.

At December 31, 2007, there was approximately $1.4 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 1.5 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at December 31, 2007	46,960	$ 32.93	$ 45.95
Expected to vest(a)	55,500	$ 32.93	$ 45.95

(a) Based on our December 31, 2007 estimated achievement of specified performance targets, the number of performance units granted in 2006 that will ultimately vest is estimated at 143% of the targeted units granted.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

Phantom Units — In conjunction with our initial public offering, in January 2006 our General Partner's board of directors awarded phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. Of the remaining Phantom Units outstanding at December 31, 2007, 2,001 units are expected to vest on January 3, 2008 and 17,698 units are expected to vest on January 3, 2009.

In 2007, we granted 4,500 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2007. Of these Phantom Units, 4,000 units vested during 2007 and 500 units are expected to vest on February 7, 2008.

The DERs are paid quarterly in arrears.

At December 31, 2007, there was approximately $0.3 million of unrecognized compensation expense related to the Phantom Units that is expected to be recognized over a weighted-average period of 1.0 year. The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(2,333)	$ 24.05	
Vested	(6,668)	$ 35.23	
Outstanding at December 31, 2007	20,199	$ 24.56	$ 45.95
Expected to vest	20,199	$ 24.56	$ 45.95

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

We intend to settle the awards issued under the LTIP in cash upon vesting, with the exception of the units granted to directors. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of our common units at each measurement date. During the year ended December 31, 2007, 2,668 units vested and were settled in cash for $0.1 million, and 4,000 units were settled with the issuance of limited partner units.

14. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. The 2005 income tax expense reflected on our consolidated statements of operations is applicable to our wholesale propane logistics business. On December 7, 2005, our wholesale propane logistics business changed its tax structure, which resulted in its activities changing from taxable to non-taxable for federal income tax purposes. The change in tax structure resulted in the reversal of the net deferred tax liabilities in the year ended December 31, 2005. Accordingly, we had no deferred tax balances as of December 31, 2007 and 2006, and no federal income tax expense for the years ended December 31, 2007 and 2006.

In May 2006, the state of Texas enacted a margin-based franchise tax into law that replaced the existing franchise tax, commonly referred to as the Texas margin tax. The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. As a result of the change in Texas franchise law, our status in the state of Texas changed from non-taxable to taxable. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year. Accordingly, we recorded current tax expense for the Texas margin tax, beginning in 2007. The deferred and current tax liabilities associated with the Texas margin tax were insignificant.

Income tax expense for the year ended December 31, 2007, consisted of current expense of $0.1 million, related primarily to the Texas margin tax. We did not have income tax expense in 2006. Income tax expense for the year ended December 31, 2005, consisted of current expense of $3.8 million and deferred benefit of

$0.5 million. Our effective tax rate differs from statutory rates, primarily due to being structured as a limited partnership, which is a pass-through entity for United States income tax purposes, while being treated as a taxable entity in certain states, and having a taxable subsidiary in 2005.

15. Net Income per Limited Partner Unit

Our net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to income or loss allocated to predecessor operations and incentive distributions paid to the general partner.

Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

These required disclosures do not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per LPU. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per LPU. During the year ended December 31, 2007, no additional earnings were allocated to the general partner. During the year ended December 31, 2006, our aggregate net income per limited partner unit exceeded the Second Target Distribution level, and as a result we allocated $1.3 million in additional earnings to the general partner.

Basic and diluted net income per LPU is calculated by dividing limited partners’ interest in net income, less pro forma general partner incentive distributions as described above, by the weighted-average number of outstanding LPUs during the period.

The following table illustrates our calculation of net income per LPU:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(Millions)	
Net (loss) income	$ (15.8)	$ 61.9
Less:		
Net income attributable to predecessor operations	(3.6)	(26.6)
Net (loss) income attributable to the partnership	(19.4)	35.3
Less: General partner interest in net income	(2.2)	(0.7)
Limited partners’ interest in net (loss) income	(21.6)	34.6
Less: Additional earnings allocation to general partner	—	(1.3)
Net (loss) income available to limited partners	$ (21.6)	$ 33.3
Net (loss) income per LPU — basic and diluted	$ (1.05)	$ 1.90

16. Commitments and Contingent Liabilities

Litigation

Driver — In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against DCP Midstream, LP, an affiliate of the owner of our general partner, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of our Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver's position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

El Paso — In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of our general partner, DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our ownership of this asset. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Other — We are not a party to any other significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated results of operations, financial position, or cash flows.

Insurance — We contract with a third party insurer for our primary general liability insurance covering third party exposures, and for our property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense. DCP Midstream, LLC provides our remaining insurance coverage through third party insurers for: (1) statutory workers' compensation insurance; (2) automobile liability insurance for all owned, non-owned and hired vehicles; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Indemnification — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessors. See the "Indemnification" section of Note 5 for additional details.

Other Commitments and Contingencies — We utilize assets under operating leases in several areas of operation. Consolidated rental expense, including leases with no continuing commitment, amounted to $11.4 million, $11.2 million and $10.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows at December 31, 2007:

	(Millions)
2008	$ 9.7
2009	7.9
2010	7.1
2011	6.2
2012	5.8
Thereafter	7.0
Total minimum rental payments	$ 43.7

17. Business Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) Wholesale Propane Logistics; and (3) NGL Logistics.

Natural Gas Services — The Natural Gas Services segment consists of (1) the Northern Louisiana system; (2) the Southern Oklahoma system that was acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the losses associated with the Swap acquired in July 2007; and (4) the assets of the MEG subsidiaries that were acquired in August 2007.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal and access to several open access pipeline terminals.

NGL Logistics — The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline. Prior to December 7, 2005, our equity interest was 50%. DCP Midstream, LLC owns a 5% interest in Black Lake, effective with the date of our initial public offering, and an affiliate of BP PLC owns the remaining interest and is the operator of Black Lake. The Wilbreeze transportation pipeline began operations in December 2006.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

The following tables set forth our segment information:

Year Ended December 31, 2007:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
			(Millions)		
Total operating revenue	$ 404.1	$ 459.6	$ 9.6	$ —	$ 873.3
Gross margin(a)	$ 16.2	$ 25.5	$ 4.9	$ —	$ 46.6
Operating and maintenance expense	(20.9)	(10.4)	(0.8)	—	(32.1)
Depreciation and amortization expense	(21.9)	(1.1)	(1.4)	—	(24.4)
General and administrative expense	—	—	—	(24.1)	(24.1)
Earnings from equity method investments	38.7	—	0.6	—	39.3
Interest income	—	—	—	5.3	5.3
Interest expense	—	—	—	(25.8)	(25.8)
Income tax expense(b)	—	—	—	(0.1)	(0.1)
Non-controlling interest in income	(0.5)	—	—	—	(0.5)
Net income (loss)	$ 11.6	$ 14.0	$ 3.3	$ (44.7)	$ (15.8)
Capital expenditures	$ 16.2	$ 3.9	$ 1.2	$ —	$ 21.3

Year Ended December 31, 2006:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
			(Millions)		
Total operating revenue	$ 415.3	$ 375.2	$ 5.3	$ —	$ 795.8
Gross margin(a)	$ 75.3	$ 16.0	$ 4.1	$ —	$ 95.4
Operating and maintenance expense	(13.5)	(8.6)	(1.6)	—	(23.7)
Depreciation and amortization expense	(11.1)	(0.8)	(0.9)	—	(12.8)
General and administrative expense	—	—	—	(21.0)	(21.0)
Earnings from equity method investments	28.9	—	0.3	—	29.2
Interest income	—	—	—	6.3	6.3
Interest expense	—	—	—	(11.5)	(11.5)
Net income (loss)	$ 79.6	$ 6.6	$ 1.9	$ (26.2)	$ 61.9
Capital expenditures	$ 6.5	$ 9.4	$ 11.3	$ —	$ 27.2

Year Ended December 31, 2005:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
			(Millions)		
Total operating revenues	$ 592.8	$ 359.8	$ 191.7	$ —	$ 1,144.3
Gross margin(a)	$ 71.4	$ 21.8	$ 3.8	$ —	$ 97.0
Operating and maintenance expense	(14.0)	(8.2)	(0.2)	—	(22.4)
Depreciation and amortization expense	(10.8)	(1.0)	(0.9)	—	(12.7)
General and administrative expense	—	—	—	(14.2)	(14.2)
Earnings from equity method investments	25.3	—	0.4	—	25.7
Interest income	—	—	—	0.5	0.5
Interest expense	—	—	—	(0.8)	(0.8)
Income tax expense(b)	—	—	—	(3.3)	(3.3)
Net income (loss)	$ 71.9	$ 12.6	$ 3.1	$ (17.8)	$ 69.8
Capital expenditures	$ 7.9	$ 2.9	$ —	$ —	$ 10.8

	December 31, 2007	December 31, 2006
	(Millions)	
Segment long-term assets:		
Natural Gas Services(d)	$ 710.7	$ 311.7
Wholesale Propane Logistics	52.6	50.2
NGL Logistics	34.8	35.1
Other(e)	104.1	109.3
Total long-term assets	902.2	506.3
Current assets	218.5	159.6
Total assets	$ 1,120.7	$ 665.9

(a) Gross margin consists of total operating revenues less purchases of natural gas, propane and NGLs. Gross margin is viewed as a non-GAAP measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, gross margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.

(b) Income tax expense in 2007 relates to the Texas margin tax, and in 2005 relates to our wholesale propane logistics business, which changed its tax status in December 2005.

(c) Other consists of general and administrative expense, interest income, interest expense and income tax expense.

(d) Long-term assets for our Natural Gas Services segment increased in 2007 as a result of our Southern Oklahoma acquisition in May 2007, and our acquisition of certain MEG subsidiaries in August 2007. Long-term assets for our Natural Gas Services segment include the effects of our 25% equity interest in

East Texas, our 40% equity interest in Discovery and the Swap acquired in July 2007, for all periods presented.

(e) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, and other long-term assets.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
	2007	2006 (Millions)	2005
Cash paid for interest and income taxes:			
Cash paid for interest, net of amounts capitalized	$ 26.5	$ 11.1	$ —
Cash paid for income taxes	$ —	$ —	$ 2.6
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 5.9	$ 1.4	$ 1.1
Accounts payable related to acquisitions	$ 9.0	$ 9.9	$ —
Accrued distributions to DCP Midstream, LLC related to reimbursements	$ 0.5	$ —	$ —
Accrued contributions from DCP Midstream, LLC related to reimbursements	$ 0.3	$ —	$ —
Accrued equity-based compensation	$ 0.2	$ —	$ —

19. Quarterly Financial Data (Unaudited)

In July 2007, we acquired our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery and the Swap. Accordingly, the results of operations by quarter have been retroactively adjusted to include the results of East Texas, Discovery and the Swap, for all periods presented.

Our consolidated results of operations by quarter, as previously reported, were as follows (millions, except per unit amounts):

2007	First	Second	Six Months Ended June 30, 2007
Total operating revenues	$ 240.1	$ 186.9	$ 427.0
Operating income	$ 14.4	$ 4.0	$ 18.4
Net income	$ 12.5	$ 0.5	$ 13.0
Limited partners’ interest in net income(a)	$ 12.2	$ 0.2	$ 12.4
Basic net income per limited partner unit(a)	$ 0.58	$ 0.01	$ 0.60

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	$ 265.4	$ 160.1	$ 162.8	$ 207.5	$ 795.8
Operating income	$ 9.1	$ 9.3	$ 7.3	$ 12.2	$ 37.9
Net income	$ 8.0	$ 8.3	$ 6.1	$ 10.6	$ 33.0
Limited partners' interest in net income(a)(b)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit(a)(b)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

Our combined results of operations by quarter for our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery and the Swap for the six months ended June 30, 2007 and the years ended December 31, 2006 and 2005 were as follows (millions):

2007	First	Second	Six Months Ended June 30, 2007
Total operating revenues	$ (2.9)	$ (5.8)	$ (8.7)
Operating loss	$ (2.9)	$ (5.8)	$ (8.7)
Net income	$ 3.3	$ 0.3	$ 3.6
Limited partners' interest in net income	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	N/A	N/A	N/A	N/A	N/A
Operating income	N/A	N/A	N/A	N/A	N/A
Net income	$ 8.3	$ 7.4	$ 8.2	$ 5.0	$ 28.9
Limited partners' interest in net income	N/A	N/A	N/A	N/A	N/A
Basic net income per limited partner unit	N/A	N/A	N/A	N/A	N/A

Our consolidated results of operations by quarter for the years ended December 31, 2007, 2006 and 2005 were as follows (millions, except per unit amounts):

2007	First	Second	Third	Fourth	Year Ended December 31, 2007
Total operating revenues	$ 237.2	$ 181.1	$ 188.6	$ 266.4	$ 873.3
Operating income (loss)	$ 11.5	$ (1.8)	$ 3.9	$ (47.6)	$ (34.0)
Net income (loss)	$ 15.8	$ 0.8	$ 7.5	$ (39.9)	$ (15.8)
Limited partners' interest in net income (loss)(a)	$ 12.2	$ 0.2	$ 6.6	$ (40.6)	$ (21.6)
Basic net income (loss) per limited partner unit(a)	$ 0.58	$ 0.01	$ 0.29	$ (1.69)	$ (1.05)

2006	First	Second	Third	Fourth	Year Ended December 31, 2006
Total operating revenues	$ 265.4	$ 160.1	$ 162.8	$ 207.5	$ 795.8
Operating income	$ 9.1	$ 9.3	$ 7.3	$ 12.2	$ 37.9
Net income	$ 16.3	$ 15.7	$ 14.3	$ 15.6	$ 61.9
Limited partners’ interest in net income(a)(b)	$ 5.3	$ 8.6	$ 9.5	$ 11.1	$ 34.6
Basic net income per limited partner unit(a)(b)	$ 0.30	$ 0.47	$ 0.51	$ 0.55	$ 1.90

(a) Total limited partners’ interest in net income and basic income per limited partner unit excludes the results from our interest in East Texas, Discovery and the Swap for the period January 1, 2005 through June 30, 2007.

(b) Total limited partners’ interest in net income and basic income per limited partner unit excludes the results from our wholesale propane logistics business for the period January 1, 2006 through October 31, 2006.

(c) Total limited partners’ interest in net income and basic income per limited partner unit is calculated using net income earned by us from December 7, 2005 through December 31, 2005, excluding the results from our wholesale propane logistics business.

20. Subsequent Events

On January 24, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.57 per unit, that was paid on February 14, 2008, to unitholders of record on February 7, 2008. This distribution of $0.57 per unit exceeds the highest target distribution level (see Note 11 for discussion of distributions of available cash).

In January 2008, we received a distribution from Discovery of $11.2 million for the fourth quarter of 2007, and we contributed $1.6 million to Discovery to fund our share of a capital expansion project.

Subsequent to December 31, 2007, we executed a series of derivative instruments to mitigate a portion of our anticipated commodity exposure. We entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and we entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.

In February 2008, we satisfied the financial tests contained in our partnership agreement for the early conversion of 50% of the outstanding subordinated units held by DCP Midstream, LLC into common units. Prior to the conversion, DCP Midstream, LLC held 7,142,857 subordinated units, and after the conversion, DCP Midstream, LLC holds 3,571,429 subordinated units, which may convert into common units in the first quarter of 2009 if we satisfy certain additional financial tests contained in our partnership agreement.

In February 2008, one of our three primary propane suppliers terminated its supply contract with us. We are actively seeking alternative sources of supply and believe such supply sources are available on commercially acceptable terms.

As of March 3, 2008, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $47.9 million. On March 4, 2008, we entered into an agreement with a counterparty to certain of our swap contracts, whereby our collateral threshold was increased by $20.0 million, resulting in a corresponding reduction of our posted collateral.

In February 2008, we borrowed $35.0 million under our revolving credit facility, $10.0 million of which has since been repaid. In March 2008, we borrowed $30.0 million under our revolving credit facility and retired $30.0 million of outstanding indebtedness under our term loan facility. As a result, we liquidated $30.0 million of restricted investments securing the term loan portion of our credit facility, the proceeds of which were used for working capital purposes. As a result of the above activity, the borrowing capacity under our revolving credit facility was increased to $630.0 million. We had $585.0 million outstanding under our revolving credit facility as of March 6, 2008.

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

There were no changes in or disagreements with accountants on accounting and financial disclosures during the year ended December 31, 2007.

Item 9A. ***Controls and Procedures***

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the Commission's rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner's principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2007, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2007, our disclosure controls and procedures were effective. There were no significant changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report On Internal Control Over Financial Reporting

Our general partner is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and board of directors of our general partner regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, internal control over financial reporting may not prevent or detect misstatements. 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 policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2007 based on the framework in "Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission." Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2007.

Deloitte & Touche, LLP, an independent registered public accounting firm, has issued their report, included immediately following, regarding our internal control over financial reporting.

March 7, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
DCP Midstream Partners GP, LLC
Denver, Colorado:

We have audited the internal control over financial reporting of DCP Midstream Partners, LP and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report On Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2007 of the Company and our report dated March 7, 2008 expressed an unqualified opinion (including explanatory paragraphs referring to (1) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to operations prior to December 7, 2005 from the separate records of DCP Midstream, LLC, and (2) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the wholesale propane logistics business from the separate records maintained by DCP Midstream, LLC and (3) the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to the DCP East Texas Holdings, LLC, Discovery Producer Services, LLC, and a nontrading derivative instrument from the separate records maintained by DCP Midstream, LLC) on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

Item 9B. ***Other Information***

No information was required to be disclosed in a report on Form 8-K, but not so reported, for the quarter ended December 31, 2007.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Management of DCP Midstream Partners, LP

We do not have directors or officers, which is commonly the case with publicly traded partnerships. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is wholly-owned by DCP Midstream, LLC. The officers and directors of our General Partner are responsible for managing us. All of the directors of our General Partner are elected annually by DCP Midstream, LLC and all of the officers of our General Partner serve at the discretion of the directors. Unitholders are not entitled to participate, directly or indirectly, in our management or operations.

Board of Directors and Officers

The board of directors of our General Partner that oversees our operations currently has nine members, four of whom are independent as defined under the independence standards established by the New York Stock Exchange. The New York Stock Exchange does not require a listed limited partnership like us to have a majority of independent directors on its general partner's board of directors or to establish a compensation committee or a nominating committee. However, the board of directors of our General Partner has established an audit committee consisting of four independent members of the board, a compensation committee and a special committee to address conflict situations.

Our General Partner's board of directors annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our General Partner, either directly or indirectly as a partner, unitholder or officer of an organization that has a relationship with our General Partner.

The executive officers of our General Partner manage the day-to-day affairs of our business and devote all of their time to our business and affairs, except Mark A. Borer, our CEO and President, who devotes more than 90% of his time to our business and affairs. We also utilize employees of DCP Midstream, LLC to operate our business and provide us with general and administrative services.

Meeting Attendance and Preparation

Members of our board of directors attended at least 75% of regular board meetings and meetings of the committees on which they serve, either in person or telephonically, during 2007. In addition, directors are expected to be prepared for each meeting of the board by reviewing materials distributed in advance.

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Directors and Executive Officers

The following table shows information regarding the current directors and the executive officers of DCP Midstream GP, LLC. Directors are elected for one-year terms.

Name	Age	Position with DCP Midstream GP, LLC
Fred J. Fowler	62	Chairman of the Board
Mark A. Borer	53	President, Chief Executive Officer and Director
Thomas E. Long	51	Vice President and Chief Financial Officer
Michael S. Richards	48	Vice President, General Counsel and Secretary
Greg K. Smith	41	Vice President, Business Development
Willie C.W. Chiang	47	Director
Sigmund L. Cornelius	53	Director
Paul F. Ferguson, Jr.	58	Director
Frank A. McPherson	74	Director
Thomas C. Morris	67	Director
Thomas C. O'Connor	52	Director
Stephen R. Springer	60	Director

Our directors hold office for one year or until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

Fred J. Fowler was elected Chairman of the Board of DCP Midstream GP, LLC in April 2007. Mr. Fowler is president and chief executive officer of Spectra Energy Corp, which has a 50 percent ownership in DCP Midstream, LLC. Prior to Spectra Energy's separation from Duke Energy, Mr. Fowler served as group executive and president of Duke Energy Gas, where he was president and CEO of the company's gas businesses. Mr. Fowler joined Duke Energy in 1985 and held various roles within marketing and gas transmission for Trunkline Gas Co., Panhandle Eastern Pipe Line Co. and Texas Eastern Transmission Corp., prior to being named group vice president for PanEnergy Corp. in 1996. He became group president of energy transmission for Duke Energy in 1997. He was appointed president and chief operating officer in November 2002 and was named group executive and president of Duke Energy Gas in April 2006. Mr. Fowler has served in this position since January 2007.

Mark A. Borer was elected President and Chief Executive Officer, and director of DCP Midstream GP, LLC in November 2006. Mr. Borer was previously Group Vice President, Marketing and Corporate Development of DCP Midstream, LLC since July 2004. He previously served as Executive Vice President of Marketing and Corporate Development of DCP Midstream, LLC from May 2002 through July 2004. Mr. Borer served as Senior Vice President, Southern Division of DCP Midstream, LLC from April 1999 through May 2002. Prior to that time, Mr. Borer was Vice President of Natural Gas Marketing for Union Pacific Fuels, Inc.

Thomas E. Long was elected Vice President and Chief Financial Officer of DCP Midstream GP, LLC in September 2005. Mr. Long was previously Vice President of National Methanol Company, Duke Energy's international chemical joint venture, since December 2004. From April 2002 until December 2004, Mr. Long served as Vice President and Treasurer of DCP Midstream, LLC. From April 1, 2000 until April 2002, Mr. Long served as Vice President, Investor Relations of DCP Midstream, LLC. Mr. Long joined Duke Energy in 1979 and served in a variety of positions in accounting, finance, tax, investor relations and business development. Mr. Long is a Certified Public Accountant licensed in the state of Texas.

Michael S. Richards was elected Vice President, General Counsel and Secretary of DCP Midstream GP, LLC in September 2005. Mr. Richards was previously Assistant General Counsel and Assistant Secretary of DCP Midstream, LLC since February 2000. He was previously Assistant General Counsel and Assistant Secretary at KN Energy, Inc. from December 1997 until he joined DCP Midstream, LLC. Prior to that, he was Senior Counsel and Risk Manager at Total Petroleum (North America) Ltd. from 1994 through 1997. Mr. Richards was previously in private practice where he focused on securities and corporate finance.

Greg K. Smith was elected Vice President, Business Development of DCP Midstream GP, LLC in September 2005. Mr. Smith was previously Vice President, Corporate Development of DCP Midstream, LLC since June 2002. From July 1996 until June 2002, Mr. Smith held several positions at DCP Midstream, LLC, including Commercial Director and Senior Attorney. Mr. Smith was previously an attorney with El Paso Natural Gas from 1992 until July 1996.

Willie C.W. Chiang was elected as a director of DCP Midstream GP, LLC in December 2007. Mr. Chiang currently serves as Senior Vice President, Commercial of ConocoPhillips. Mr. Chiang has more than 26 years experience in the energy industry. He served in a variety of management positions in refining with Chevron, Powerine Oil Company, Unocal, Tosco and Phillips Petroleum prior to the merger of Phillips and Conoco in 2002. Mr. Chiang was named President, Downstream Strategy, Integration and Specialty Businesses of ConocoPhillips in 2003 and in 2005 he was named President, Americas Supply and Trading. He was named to his current position of Senior Vice President, Commercial of ConocoPhillips in 2007.

Sigmund L. Cornelius was elected as a director of DCP Midstream GP, LLC in November 2007. Mr. Cornelius currently serves as Senior Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips. Mr. Cornelius has over 27 years experience in the energy industry with ConocoPhillips. He began his career at Conoco in 1980, where he served in a variety of positions in the company's natural gas and gas products unit. After serving in a number of management positions with Conoco, he was named President and General Manager of Conoco Canada Limited in 1994 and President of Conoco affiliate Dubai Petroleum Company in 1997. In 1999 he was named Assistant Treasurer and General Manager for Mergers, Acquisitions and Structured Finance for Conoco. In 2001, Mr. Cornelius was named Treasurer of Conoco and later named Vice President and Treasurer. Following the merger with Phillips Petroleum in 2002, Mr. Cornelius became Vice President of Upstream Business Development, and in 2003 he became President, Lower 48, Latin America & Midstream. In 2004 he became President, Global Gas, and he was named President, Exploration and Production — Lower 48 in 2006. He was named to his current position in 2007.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson was a director of the general partner of TEPPCO Partners, L.P. from October 2004 until his resignation in 2005. Mr. Ferguson was a member of the Compensation, Audit and special committees of the general partner of TEPPCO Partners, L.P. Mr. Ferguson was elected Chairman of the audit committee in October 2004. He served as Senior Vice President and Treasurer of Duke Energy from June 1997 to June 1998, when he retired. Mr. Ferguson served as Senior Vice President and Chief Financial Officer of PanEnergy Corp. from September 1995 to June 1997. He held various other financial positions with PanEnergy Corp. from 1989 to 1995 and served as Treasurer of Texas Eastern Corporation from 1988 to 1989.

Frank A. McPherson was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. McPherson retired as Chairman and Chief Executive Officer from Kerr McGee Corporation in 1997 after a 40-year career with the company. Mr. McPherson was Chairman and Chief Executive Officer of Kerr McGee from 1983 to 1997. Prior to that he served in various capacities in management of Kerr McGee. Mr. McPherson joined Kerr McGee in 1957. Mr. McPherson serves on the boards of Integris Health, Tri Continental Corporation, Seligman Group of Mutual Funds, and several non-profit organizations in Oklahoma. He previously served on the boards of ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City, the Oklahoma State University Foundation Board of Trustees and the American Petroleum Institute.

Thomas C. Morris was elected as a director of DCP Midstream GP, LLC in December 2005. Mr. Morris is currently retired, having served 34 years with Phillips Petroleum Company. Mr. Morris served in various capacities with Phillips, including Vice President and Treasurer and subsequently Senior Vice President and Chief Financial Officer from 1994 until his retirement in 2001. Mr. Morris served as Vice Chairman of the board of OK Mozart, is a former member of the executive board of the American Petroleum Institute finance committee and a former member of the Business Development Council of Texas A&M University.

Thomas C. O'Connor was elected as a director of DCP Midstream GP, LLC in December 2007. Mr. O'Connor has over 20 years experience in the natural gas industry with Duke Energy prior to joining DCP Midstream, LLC in November 2007 as Chairman of the board, President and CEO. Mr. O'Connor joined Duke

Energy in 1987 where he served in a variety of positions in the company's natural gas and pipeline operations units. After serving in a number of leadership positions with Duke Energy, he was named President and Chief Executive Officer of Duke Energy Gas Transmission in 2002 and he was named Group Vice President of corporate strategy at Duke Energy in 2005. In 2006 he became Group Executive and Chief Operating Officer of U.S. Franchised Electric and Gas and later in 2006 was named Group Executive and President of Commercial Businesses at Duke Energy.

Stephen R. Springer was elected as a director of DCP Midstream GP, LLC in July 2007. Mr. Springer has over thirty years experience in the energy industry. He began his career at Texas Gas Transmission Corporation, where he served in a variety of executive management positions within gas acquisitions and gas marketing. After serving as President of Transco Gas Marketing Company, he served as Vice President of Business Development at Williams Field Services Company and then Senior Vice President and General Manager of Williams Midstream Division, the position he held until his retirement in 2002. Mr. Springer has served on the board of directors of Atmos Energy Corporation since 2005.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires DCP Midstream GP, LLC's directors and executive officers, and persons who own more than 10% of any class of our equity securities to file with the Securities and Exchange Commission, or SEC, and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of our common units and our other equity securities. Specific due dates for those reports have been established, and we are required to report herein any failure to file reports by those due dates. Directors, executive officers and greater than 10% unitholders are also required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. To our knowledge, based solely on a review of the copies of reports furnished to us and written representations that no other reports were required during the fiscal year ended December 31, 2007, all Section 16(a) filing requirements applicable to such reporting persons were complied with, except that a Form 3 was filed 14 days late for Mr. Fowler upon his appointment to the Board, and DCP Midstream, LLC and DCP LP Holdings, LLC filed a joint Form 5 in 2008 reflecting late Form 4s for the conversion of certain Class C units owned by DCP LP Holdings, LLC and the acquisition of common units as partial consideration associated with our acquisitions from DCP Midstream, LLC of certain assets in July and August, 2007.

Audit Committee

The board of directors of our General Partner has a standing audit committee. The audit committee is composed of four nonmanagement directors, Paul F. Ferguson, Jr. (chairman), Frank A. McPherson, Thomas C. Morris and Stephen R. Springer, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under Section 303A.02 of the New York Stock Exchange listing standards and Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended. In making the independence determination, the board considered the requirements of the New York Stock Exchange and our Code of Business Ethics. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities, and other material relationships with us. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

With respect to material relationships, the following relationships are not considered to be material for purposes of assessing independence: service as an officer, director, employee or trustee of, or greater than five percent beneficial ownership in (a) a supplier to the partnership if the annual sales to the partnership are less than one percent of the sales of the supplier; (b) a lender to the partnership if the total amount of the partnership's indebtedness is less than one percent of the total consolidated assets of the lender; or (c) a charitable organization if the total amount of the partnership's annual charitable contributions to the organization are less than three percent of that organization's annual charitable receipts.

Mr. Ferguson has been designated by the board as the audit committee's financial expert meeting the requirements promulgated by the SEC and set forth in Item 407(d) of Regulation S-K of the Securities

Exchange Act of 1934 based upon his education and employment experience as more fully detailed in Mr. Ferguson's biography set forth above.

Special Committee

The board of directors of our General Partner has a standing special committee, which is comprised of four nonmanagement directors, Stephen R. Springer (chairman), Paul F. Ferguson, Jr., Frank A. McPherson and Thomas C. Morris. The special committee will review specific matters that the board believes may involve conflicts of interest. The special committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The special committee meets at each quarterly meeting of the Board of Directors. The members of the special committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates. Each of the members of the special committee meet the independence and experience standards established by the New York Stock Exchange and the Securities Exchange Act of 1934, as amended. Any matters approved by the special committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our General Partner of any duties it may owe us or our unitholders.

Compensation Committee

The board of directors of our General Partner has a standing compensation committee, which is composed of four directors, Fred J. Fowler (chairman), Willie C.W. Chiang, Frank A. McPherson and Thomas C. O'Connor. The compensation committee oversees compensation decisions for the officers of our general partner and administers the long-term incentive plan, selecting individuals to be granted equity-based awards from among those eligible to participate. The compensation committee has adopted a charter, which has been ratified and approved by the board of directors.

Corporate Governance Guidelines and Code of Business Ethics

Our board of directors has adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

We have adopted a Code of Business Ethics applicable to the persons serving as our directors, officers (including without limitation, the chief executive officer, chief financial officer and principal accounting officer) and employees, which includes the prompt disclosure to the SEC of a current report on Form 8-K of any waiver of the code for executive officers or directors approved by the board of directors.

Copies of our Corporate Governance Guidelines, our Code of Business Ethics, our Audit Committee Charter and our Compensation Committee Charter are available on our website at *www.dcppartners.com*. Copies of these items are also available free of charge in print to any unitholder who sends a request to the office of the Secretary of DCP Midstream Partners, LP at 370 17th Street, Suite 2775, Denver, Colorado 80202.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the special committee, the committee, which consists of all of our non-management directors, meets in an executive session without management participation or participation by non-independent directors. The chairman of the special committee presides over these executive sessions.

Unitholders or interested parties may communicate with any and all members of our board, including our nonmanagement directors, or any committee of our board, by transmitting correspondence by mail or facsimile addressed to one or more directors by name or to the chairman of the board or any committee of the board at the following address and fax number; Name of the Director(s), c/o Secretary, DCP Midstream Partners, LP, 370 17th Street, Suite 2775, Denver, Colorado 80202, (303) 633-2921.

New York Stock Exchange, or NYSE, Annual Certification

On January 25, 2007, Mark A. Borer, our Chief Executive Officer, certified to the NYSE, as required by NYSE rules, that as of January 25, 2007, he was not aware of any violation by us of the NYSE's Corporate Governance Listing Standards.

Report of the Audit Committee

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls. The audit committee operates under a written charter approved by the board of directors. The charter, among other things, provides that the audit committee has authority to appoint, retain and oversee the independent auditor. In this context, the audit committee:

- reviewed and discussed the audited financial statements in this annual report on Form 10-K with management, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;
- reviewed with Deloitte & Touche, LLP, our independent auditors, who are responsible for expressing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of our accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards;
- received the written disclosures and the letter required by standard No. 1 of the independence standards board (independence discussions with audit committees) provided to the audit committee by Deloitte & Touche, LLP;
- discussed with Deloitte & Touche, LLP its independence from management and us and considered the compatibility of the provision of nonaudit service by the independent auditors with the auditors' independence;
- discussed with Deloitte & Touche, LLP the matters required to be discussed by statement on auditing standards No. 61 (communications with audit committees);
- discussed with our internal auditors and Deloitte & Touche, LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Deloitte & Touche, LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of our financial reporting;
- based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the annual report on Form 10-K for the year ended December 31, 2007, for filing with the Securities and Exchange Commission; and
- approved the selection and appointment of Deloitte & Touche, LLP to serve as our independent auditors. This report has been furnished by the members of the audit committee of the board of directors:

Audit Committee

Paul F. Ferguson, Jr. (Chairman)
Frank A. McPherson
Thomas C. Morris
Stephen R. Springer

March 7, 2008

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by DCP Midstream Partners, LP under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such acts.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

General

As a publicly traded limited partnership, we do not have directors, officers or employees. Instead, our operations are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is a wholly-owned subsidiary of DCP Midstream, LLC.

As of March 3, 2008, our General Partner has four executive officers and five additional employees. All of these employees are solely dedicated to our operations and management, except our President and Chief Executive Officer, or CEO, who devotes more than 90% of his time to our operations and management. The General Partner has not entered into employment agreements with any of our executive officers. The compensation committee of our General Partner's board of directors establishes the compensation program for these employees.

Compensation Committee

The compensation committee is comprised of directors of our General Partner and has four members as of March 3, 2008. The compensation committee's responsibilities include, among other duties, the following:

- annually review and approve Partnership goals and objectives relevant to compensation of the CEO and other executive officers;
- annually evaluate the CEO's performance in light of the Partnership goals and objectives, and approve the compensation levels for the CEO and other executive officers;
- periodically evaluate the terms and administration of the Partnership's short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with the Partnership's goals and objectives;
- periodically evaluate incentive compensation and equity-related plans and consider amendments if appropriate;
- periodically evaluate the compensation of the directors;
- retain and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or executive officer compensation; and
- perform other duties as deemed appropriate by the General Partner's board of directors.

Compensation Philosophy

Our compensation program is structured to provide the following benefits:

- Attract, retain and reward talented executive officers and key management employees by providing total compensation competitive with that of other executive officers and key management employees employed by publicly traded limited partnerships of similar size or in similar lines of business;
- Motivate executive officers and key management employees to achieve strong financial and operational performance;
- Emphasize performance-based compensation, balancing short-term and long-term results;
- Reward individual performance; and
- Encourage a long-term commitment to the Partnership by requiring target levels of unit ownership.

Methodology

The compensation committee reviews data from market surveys provided by independent consultants to assess the competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation. With respect to executive officer compensation, the compensation committee also considers individual performance, levels of responsibility, skills and experience. In 2007 we engaged the services of BDO Seidman, LLP (successor to Apogee), or BDO, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for our executives. The study was based on compensation as reported in the annual reports on Form 10-K for a group of peer companies with a similar tax status, and the 2007 Towers Perrin General Industry Executive Compensation Database, or the Towers Perrin Database. The study was comprised of the following companies: Boardwalk Pipeline Partners, LP, Buckeye Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., Enbridge Energy Partners, L.P., Genesis Energy, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., ONEOK Partners, L.P., Plains All American Pipeline, L.P., Regency Energy Partners LP and Sunoco Logistics Partners L.P. Studies such as this generally include only the most highly compensated officers of each company, which correlates with our executive officers. The results of this study, as well as other factors such as our targeted performance objectives, served as a benchmark for establishing our total direct compensation packages. In order to assess the competitiveness of the total direct compensation packages for our executive officers we used the median amount for peer positions from the BDO study and the data point that represents the 50th percentile of the market in the Towers Perrin Database.

Components of Compensation

The total annual direct compensation program for executives of the General Partner consists of three components: (1) base salary; (2) an annual short-term cash incentive, or STI, which is based on a percentage of annual base salary; and (3) the present value of an equity-based cash settled grant under our long-term incentive plan, or LTIP. Under our compensation structure, the allocation between base salary, STI and LTIP varies depending upon job title and responsibility levels. In 2007, this allocation for targeted compensation of our executive officers was as follows:

	Base Salary	Targeted STI Level	Targeted LTIP Level
CEO	34%	21%	45%
Chief Financial Officer, or CFO	44%	20%	36%
Vice Presidents	44%	20%	36%

In allocating compensation among these components, we believe the compensation of our executive officers should be more heavily weighted toward performance-based compensation since these individuals have a greater opportunity to influence the our performance. In making this allocation, we have relied in part on the BDO study of the companies named above. Each component of compensation is further described below.

Base Salary — Base salaries for executives are determined based upon job responsibilities, level of experience, individual performance, and comparisons to the salaries of executives in similar positions obtained from the BDO study. The goal of the base salary component is to compensate executives at a level that approximates the median salaries of individuals in comparable positions at comparably sized companies in our industry.

The base salaries for executives are generally reevaluated annually as part of our performance review process, or when there is a change in the level of job responsibility. The base salaries paid to our executive officers are set forth in the “Summary Compensation” table below.

Annual Short-Term Cash Incentive, or STI — Under the STI, annual cash incentives are provided to executives to promote the achievement of our performance objectives. Target incentive opportunities for executives under the STI are established as a percentage of base salary. Incentive amounts are intended to provide total cash compensation at the market median for executive officers in comparable positions and markets when target performance is achieved, below the market median when performance is less than target and above the market median when performance exceeds target. The BDO study was used to determine the competitiveness of the incentive opportunity for comparable positions. STI payments are generally paid in cash in March of each year for the prior fiscal year's performance.

In 2007, the STI objectives were initially designed and proposed by the executive officers and presented to the Chairman of the General Partner's board of directors. These objectives were then considered and approved by the compensation committee and ultimately by the full board of directors. In 2007, the STI objectives approved by the compensation committee were divided as follows: (1) company objectives accounted for 75% of the STI; and (2) personal objectives accounted for 25% of the STI. The target incentive opportunities for 2007 as a percentage of base salary for the CEO, the CFO, and the Vice Presidents were 60%, 45% and 45%, respectively. All STI objectives are subject to change each year.

The 2007 stated company objectives under the STI were based on the following and were weighted as indicated:

1) The achievement of certain levels of distributable cash flow relative to the forecast in our 2007 budget, excluding the drop down acquisition of assets from DCP Midstream, LLC, third party acquisitions and the costs associated with such transactions. As a publicly traded limited partnership, our performance is generally judged on our ability to pay cash distributions to our unitholders. We use distributable cash flow as the financial objective because we believe it is a useful measure of our ability to make such cash distributions. For this company objective, the target level of performance is the 2007 budget, the maximum level of performance is approximately 16% higher than budget and the minimum level of performance is approximately 12% lower than budget. The weighting of this objective relative to the other stated company objectives was 35%.

2) Total return to unitholders relative to a peer group of 15 other similar public limited partnerships our size and maturity. We used a different peer group than we used in the overall compensation peer group so that our unit performance would be compared to public limited partnerships that were similar to us in market size and maturity. This peer group was comprised of the companies within the *UBS MLP Weekly Report,* Mid Cap Midstream category. The companies included in this category at the start of 2007 were the following: Atlas Pipeline Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., Eagle Rock Energy Partners, L.P., Exterran Partners, L.P., Genesis Energy, L.P., Hiland Partners, LP, Holly Energy Partners, L.P., MarkWest Energy Partners, L.P., Martin Midstream Partners L.P., Regency Energy Partners LP, Sunoco Logistics Partners, L.P., TC PipeLines, LP, TransMontaigne Partners L.P. and Williams Partners, L.P. For this company objective, the target level of performance is the top 60th percentile in total unitholder return as compared to this peer group, the maximum level of performance is the top 80th percentile in total unitholder return of this peer group and the minimum level of performance is the top 40th percentile in total unitholder return of this peer group. The weighting of this objective relative to the other stated company objectives was 30%.

3) Establishing and maintaining strong internal controls and accounting accuracy while meeting the performance requirements of the Sarbanes-Oxley Act of 2002. For this company objective, the target level of performance will be based upon the judgment of the Chairman of the Audit Committee, taking into consideration the number of significant deficiencies and if they are identified by the external auditor. The maximum level of performance for this company objective will be based upon our having no reportable conditions or significant deficiencies identified and reported to the Audit Committee by the external auditor, and the minimum level of performance will be based on having no material weaknesses identified by management or the external auditor. The weighting of this objective relative to the other stated company objectives was 15%.

4) Successful completion of a drop down from DCP Midstream, LLC. For this company objective, the level of performance will be determined by the judgment of the Chairman of the Board and the Compensation Committee, taking into consideration the project's success. The weighting of this objective relative to the other stated company objectives was 20%.

The payout on these company objectives ranged from 0% if the minimum level of performance was not achieved, 50% if the minimum level of performance was achieved, 100% if the target level of performance was achieved and 200% if the maximum level of performance was achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation. For fiscal year 2007, the payout levels were as follows:

STI Objective	Payout Level	Level of Performance Achieved
Distributable cash flow	200%	Maximum
Total return to unitholders	166%	Between Target and Maximum
Internal controls	200%	Maximum
Drop down	138%	Between Target and Maximum

The 2007 stated personal objectives under the STI were based on a number of individual performance objectives for each employee, which included items such as distribution growth, maintenance of strong liquidity in the debt and equity capital markets, and execution of our growth strategies. The personal objectives were approved by the compensation committee for the CEO, and by the CEO for the other executive officers. The payout on the individual personal objectives ranged from 0% if the minimum level of performance was not achieved, 75% if the minimum level of performance was achieved, 100% if the target level of performance was achieved and 125% if the maximum level of performance was achieved. When the performance level falls between these percentages, payout will be determined by straight-line interpolation. For fiscal year 2007, the aggregate level of performance achieved by the executive officers on their personal objectives was 115%.

Long-Term Incentive Plan, or LTIP — The long-term incentive compensation program has the objective of providing a focus on long-term value creation and enhancing executive retention. Under our LTIP program, we make cash payments to each executive officer if certain performance objectives are achieved within a three year period, and such executive officer remains employed with us during this period. We believe this program promotes retention of our executive officers, and focuses our executive officers on the goal of long-term value creation through the long-term growth in our distributable cash flow.

For 2007, the compensation committee awarded our executive officers phantom limited partnership units, or phantom LPUs, which vest in their entirety at the end of a three-year measurement period, or the Performance Period, to the extent the performance measure is achieved during the Performance Period. These awards were granted at the first regular board of directors' meeting during the first quarter of 2007. The number of awards granted to our executive officers is set forth in the "Grants of Plan-Based Awards" table below. Award recipients also received the right to receive distribution equivalent rights, or DERs, on the number of units earned during the Performance Period. Our practice is to determine the dollar amount of long-term incentive compensation that we want to provide, and to then grant a number of phantom LPUs that have a fair market value equal to that amount on the date of grant, which is based on the closing price of our common units on the New York Stock Exchange on the date of grant. Target long-term incentive opportunities for executives under the plan are established as a percentage of base salary, using the BDO study data for individuals in comparable positions. The target 2007 long-term incentive opportunities, expressed as a percentage of base salary, for the CEO, the CFO and the Vice Presidents were 130%, 80% and 80%, respectively.

Both the phantom LPUs and the DERs will be paid in cash upon vesting. The amount paid on the phantom LPUs will be based on the product of the number of LPUs earned times the average fair market value of our common units on the last ten trading days immediately prior to the end of the Performance Period. The amount paid on the DERs will equal the quarterly distributions actually paid during the Performance Period on the number of LPUs earned.

For the phantom LPUs granted in 2007, the performance measure is growth capital substantially approved by our board of directors over the Performance Period. This performance measure was initially designed and proposed by the executive officers and presented to the Chairman of the General Partner's board of directors. These objectives were then considered and approved by the compensation committee and ultimately by the full board of directors. For the Performance Period, approved growth capital will be all growth capital approved by the board of directors, but excludes items that are typically included as maintenance capital in management's periodic reports to the board of directors. The compensation committee believes utilizing growth capital as a performance measure provides incentive for the continued growth of our operating footprint and distributions to unitholders. This performance measure, coupled with the 2007 STI objectives to meet or exceed distributable cash flow targets and to achieve a superior total return relative to our peer group, provides management with appropriate incentives for our disciplined and steady growth. If approved growth capital over the Performance Period is less than $500 million, none of the phantom LPUs will vest. If approved growth capital over the Performance Period is $500 million or greater but less than $900 million, 50% of the phantom LPUs will vest. If approved growth capital over the Performance Period is $900 million or greater, but less than $1.5 billion, 100% of the phantom LPUs will vest. If approved growth capital over the Performance Period is $1.5 billion or more, 150% of the phantom LPUs will vest. When approved growth capital falls between the 50%, 100% and 150% levels, vesting will be determined by straight-line interpolation. The compensation committee may, in its sole discretion, increase or decrease the percentage of units vesting by up to 25 percentage points to reflect its evaluation of key performance issues that may not be captured by the performance measure.

In the event that any person other than DCP Midstream, LLC and/or an affiliate thereof becomes the beneficial owner of more than 50% of the combined voting power of the General Partner's equity interests prior to the completion of the Performance Period, the phantom LPUs and related DERs will vest pro rata based on the number of days that have lapsed in the Performance Period through the date of the change of control, and the remainder of the LPUs and DERs that do not vest will be forfeited. The vested phantom LPUs and related DERs will be paid in cash. In the event an award recipient's employment is terminated for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, the recipient (or his estate) will be entitled to a pro rata amount of the award based upon the percentage of the Performance Period the recipient was employed and our performance. Termination of employment for any other reason will result in the forfeiture of any unvested units.

Other Compensation — In addition, our executives are eligible to participate in other compensation programs, which include but are not limited to:

IPO Phantom Units — In conjunction with our initial public offering, in January 2006 our General Partner's board of directors granted phantom LPUs, or phantom IPO LPUs, to key employees, including the executive officers, which vest in their entirety three years following the grant date. Upon vesting, the phantom LPUs will be paid in common units or, at the discretion of the compensation committee, cash based on the fair market value of our common units on the payment date. There is no performance condition associated with these phantom LPUs. Award recipients also receive DERs based on the number of common units awarded, which are paid in cash on a quarterly basis from the date of the initial grant. These phantom LPUs were granted to reward those key employees and executive officers that made significant contributions to our successful initial public offering. The amounts of awards granted to our executive officers are set forth in the "Grants of Plan-Based Awards" table below.

In the event that any person other than DCP Midstream, LLC and/or an affiliate thereof becomes the beneficial owner of more than 50% of the combined voting power of the General Partner's equity interests prior to the completion of the vesting period, all the phantom IPO LPUs will become fully vested upon such change of control, and will be paid in common units, or in the compensation committee's sole discretion, cash. If cash is paid, the amount will be determined based upon the closing price of our common units on the New York Stock Exchange upon such change of control. In the event an award recipient's employment is terminated for reasons of death, disability, early or normal retirement, or if the recipient is terminated by the General Partner for reasons other than cause, the phantom IPO LPUs will immediately vest and the recipient (or his estate) will be entitled to the full amount of the award. Termination of employment for any other reason will result in the forfeiture of any unvested units.

Company Retirement Contributions — Employees may elect to participate in the DCP Midstream, LP 401(k) and Retirement Plan. Under the plan, employees may elect to defer up to 75% of their eligible compensation, or up to the limits specified by the Internal Revenue Service. We match the first 6% of eligible compensation contributed by the employee to the plan. In addition, we make retirement contributions ranging from 4% to 7% of the eligible compensation of qualifying participants to the plan, based on years of service, up to the limits specified by the Internal Revenue Service.

Miscellaneous Compensation — Our executive officers are eligible to participate in a nonqualified deferred compensation program. Executive officers are allowed to defer up to 75% of their base salary, and up to 100% of their STI, LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to 20 years) at termination.

Executive officers and other eligible employees may participate in a noncontributory, defined benefit retirement plan. Benefits earned under this plan are attributable to compensation in excess of the annual compensation limits under section 401(k) of the Internal Revenue Code. Under this plan, we make a contribution of up to 10% of eligible compensation, as defined by this plan, to the nonqualified deferred compensation program.

In addition, we provide our employees, including the executive officers, with a variety of health and welfare benefit programs. The health and welfare programs are intended to protect employees against catastrophic loss and promote well being. These programs include medical, wellness, pharmacy, dental, vision, life insurance premiums, and accidental death and disability. In addition, we pay certain perquisites to our executives, which include items such as financial planning, club dues and an allowance towards annual medical expenses. Finally, we provide all our employees with a monthly parking pass or a pass to be used on available public transportation systems.

None of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

Other

Unit Ownership Guidelines — To underscore the importance of linking executive and unitholder interests, the board of directors of our General Partner has adopted unit ownership guidelines for executive officers and key employees who are eligible to receive long-term incentive awards. To that extent, the board has established target equity ownership obligations for the various levels of executives, which have a five-year build term that commenced in 2006. Ownership is reported annually to the compensation committee. As of December 31, 2007, the unit ownership guidelines for the executive officers were as follows:

	Number of Units
CEO	28,000
CFO	10,000
Vice Presidents	10,000

Report of the Compensation Committee

The compensation committee has reviewed and discussed with management the “Compensation Discussion and Analysis” presented above. Members of management with whom the compensation committee had discussions are the Chief Executive Officer of the General Partner and the Vice President, Human Resources of DCP Midstream, LLC. In addition, the compensation committee engaged the services of BDO Seidman, LLP, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for our executives. Based on this review and discussion, we recommended to the board of directors of the General Partner that the “Compensation Discussion and Analysis” referred to above be included in this annual report on Form 10-K for the year ended December 31, 2007.

Compensation Committee

Fred J. Fowler (Chairman)
Willie C.W. Chiang
Frank A. McPherson
Thomas C. O’Connor

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Executive Compensation

The following table discloses the compensation of the General Partner's principal executive officers, principal financial officer and named executive officers, or collectively, the "executive officers":

Name and Principal Position	Summary Compensation Year	Salary	LPU Awards(b)	Non-Equity Incentive Plan Compensation	Change in Nonqualified Deferred Compensation Earnings(c)	All Other Compensation(d)	Total
Mark A. Borer(a)	2007	$341,000	$151,763	$331,043	$36,518	$80,908	$941,232
President and Chief Executive Officer	2006	$ 47,215	$ —	$ 46,655	$ 45	$ 2,052	$ 95,967
Thomas E. Long	2007	$199,212	$247,605	$145,605	$ 1,584	$54,268	$648,274
Vice President and Chief Financial Officer	2006	$180,000	$ 92,191	$133,650	$ —	$33,182	$439,023
Michael S. Richards	2007	$172,615	$229,360	$125,903	$ 48	$46,431	$574,357
Vice President, General Counsel and Secretary	2006	$165,000	$ 88,390	$122,048	$ —	$32,717	$408,155
Greg K. Smith	2007	$179,644	$234,724	$131,080	$ 866	$51,185	$597,499
Vice President, Business Development	2006	$170,000	$ 89,600	$121,444	$ 480	$36,044	$417,568

(a) Mr. Borer's employment with the General Partner commenced effective November 10, 2006.

(b) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes, in accordance with the provisions of Statement of Financial Standards No. 123, *Share-Based Payment*, as revised, or SFAS 123R, and include amounts from awards granted in January 2006 related to our initial public offering, and awards granted in conjunction with our LTIP during 2007 and 2006. See Note 13 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

(c) Amounts in this column are also included in the "Nonqualified Deferred Compensation" table below.

(d) Includes DERs, company retirement and nonqualified deferred compensation program contributions by the Partnership, the value of life insurance premiums paid by the Partnership on behalf of an executive and other deminimus compensation.

Mark A. Borer, President and CEO

The annual base salary for Mr. Borer was $341,000 for both 2007 and 2006, of which he deferred $120,391 and $8,944 in 2007 and 2006, respectively. The LPU awards are comprised of phantom LPUs pursuant to the LTIP. Under both the 2007 and 2006 STI, Mr. Borer's target opportunity was 60% of his annual base salary, with the possibility of earning from 0% to 109% of his annual base salary, depending on the level of performance in each of the STI objectives, which was pro rated in 2006 based upon his service period during 2006. While an employee at DCP Midstream, LLC during 2006, he received various equity grants and other compensation which are not reflected as part of the compensation attributable to his service with the Partnership.

"All Other Compensation" includes the following:

- Company retirement contributions of $29,250 and $0 for 2007 and 2006, respectively;
- Nonqualified deferred compensation program contributions of $32,063 and $1,945 for 2007 and 2006, respectively;
- DERs of $18,370 and $0 for 2007 and 2006, respectively;
- Life insurance premiums of $1,225 and $107 for 2007 and 2006, respectively, paid by the Partnership on behalf of Mr. Borer.

Thomas E. Long, Vice President and CFO

The annual base salary for Mr. Long was $199,980 and $180,000 for 2007 and 2006, respectively, of which he deferred $89,645 and $0 in 2007 and 2006, respectively. The LPU awards are comprised of phantom IPO LPUs and phantom LPUs pursuant to the LTIP. Under both the 2007 and 2006 STI, Mr. Long's target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

- Company retirement contributions of $28,476 and $21,553 for 2007 and 2006, respectively;
- DERs of $25,075 and $10,981 for 2007 and 2006, respectively; and
- Life insurance premiums of $717 and $648 for 2007 and 2006, respectively, paid by the Partnership on behalf of Mr. Long.

Michael S. Richards, Vice President, General Counsel and Secretary

The annual base salary for Mr. Richards was $172,920 and $165,000 for 2007 and 2006, of which he deferred $3,452 and $0 in 2007 and 2006, respectively. The LPU awards are comprised of phantom IPO LPUs and phantom LPUs pursuant to the LTIP. Under both the 2007 and 2006 STI, Mr. Richards' target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

- Company retirement contributions of $22,500 and $20,891 for 2007 and 2006, respectively;
- DERs of $23,309 and $10,482 for 2007 and 2006, respectively;
- Life insurance premiums of $622 and $594 for 2007 and 2006, respectively, paid by the Partnership on behalf of Mr. Richards; and
- A deminimus bonus of $0 and $750 for 2007 and 2006, respectively.

Greg K. Smith, Vice President, Business Development

The annual base salary for Mr. Smith was $180,030 and $170,000 for 2007 and 2006, respectively, of which he deferred $7,186 and $6,800 in 2007 and 2006, respectively. The LPU awards are comprised of phantom IPO LPUs and phantom LPUs pursuant to the LTIP. Under both the 2007 and 2006 STI, Mr. Smith's target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 82% of his annual base salary, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

- Company retirement contributions of $23,855 and $21,928 for 2007 and 2006, respectively;
- DERs of $23,818 and $10,640 for 2007 and 2006, respectively;
- Nonqualified deferred compensation program contributions of $2,864 for both 2007 and 2006; and
- Life insurance premiums of $648 and $612 for 2007 and 2006, respectively, paid by the Partnership on behalf of Mr. Smith.

Grants of Plan-Based Awards

Following are the grants of plan-based awards for the General Partner's executive officers:

Name	Grant Date	Estimated Future Payouts under Non-Equity Incentive Plan Awards(a) Minimum ($)	Target ($)	Maximum ($)	Estimated Future Payouts under Equity Incentive Plan Awards Minimum (#)	Target (#)	Maximum (#)	Grant Date Fair Value of LPU Awards ($)
Mark A. Borer	NA	$115,088	$204,600	$370,838	—	—	—	—
	2/26/2007(b)	$ —	$ —	$ —	5,945	11,890	17,835	$443,378
Thomas E. Long	NA	$ 50,620	$ 89,991	$163,109	—	—	—	—
	2/26/2007(b)	$ —	$ —	$ —	2,145	4,290	6,435	$159,974
Michael S. Richards	NA	$ 43,770	$ 77,814	$141,038	—	—	—	—
	2/26/2007(b)	$ —	$ —	$ —	1,855	3,710	5,565	$138,346
Greg K. Smith	NA	$ 45,570	$ 81,014	$146,837	—	—	—	—
	2/26/2007(b)	$ —	$ —	$ —	1,930	3,860	5,790	$143,939

(a) Amounts shown represent amounts under the STI. If minimum levels of performance are not met, then the payout for one or more of the components of the STI may be zero.

(b) The number of units shown on the line with the grant date of 2/26/2007 represents units awarded under the LTIP. If minimum levels of performance are not met, then the payout may be zero.

The phantom LPUs pursuant to the LTIP were awarded on February 26, 2007, and will vest in their entirety on December 31, 2009 if the specified performance conditions are satisfied.

Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the General Partner's executive officers as of December 31, 2007:

Name	Outstanding LPU Awards: Units That Have Not Vested(a)	Market Value of Units That Have Not Vested(b)	Equity Incentive Plan Awards: Unearned Units That Have Not Vested(c)	Equity Incentive Plan Awards: Market Value of Unearned Units That Have Not Vested(b)
Mark A. Borer	—	$ —	11,890	$ 546,346
Thomas E. Long	4,000	$ 183,800	9,630	$ 548,009
Michael S. Richards	4,000	$ 183,800	8,610	$ 492,446
Greg K. Smith	4,000	$ 183,800	8,900	$ 508,538

(a) Phantom IPO LPUs awarded 1/3/2006; units vest in their entirety on 1/3/2009. For additional information, see "Compensation Discussion and Analysis — Other Compensation — IPO Phantom Units."

(b) Value calculated based on the closing price of our common units at December 31, 2007.

(c) Phantom LPUs pursuant to the LTIP awarded 5/5/2006 and 2/26/2007; units vest in their entirety over a range of 0% to 150% on 12/31/2008 and 12/31/2009, respectively, if the specified performance conditions are satisfied; to determine the market value, the calculation of the number of units that are expected to vest for units granted in 2007 is based on assumed performance at "target" performance levels, and for units granted in 2006 is based on assumed performance at 143%.

Options Exercises and Stock Vested

There were no options exercised and no limited partnership units held by our executive officers that vested during the year ended December 31, 2007.

Nonqualified Deferred Compensation

Following is the nonqualified deferred compensation for the General Partner's executive officers for the year ended December 31, 2007:

Name	Executive Contributions in Last Fiscal Year (a)	Registrant Contributions in Last Fiscal Year(b)	Aggregate Earnings in Last Fiscal Year(c)	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2007
Mark A. Borer	$ 120,391	$ 32,063	$ 36,518	$ —	$ 669,361
Thomas E. Long	$ 89,645	$ —	$ 1,584	$ —	$ 91,374
Michael S. Richards	$ 3,452	$ —	$ 48	$ —	$ 3,526
Greg K. Smith	$ 7,186	$ 2,864	$ 866	$ —	$ 31,650

(a) These amounts were included in the gross salary reported in the "Salary" column of the "Summary Compensation" table.

(b) These amounts are included in the "Summary Compensation" table within "All Other Compensation."

(c) These amounts are included in the "Summary Compensation" table as "Change in Nonqualified Deferred Compensation Earnings."

Executive officers are allowed to defer up to 75% of their base salary, and up to 100% of their STI, LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to 20 years) at termination.

Potential Payments Upon Termination or Change in Control

As noted above, the General Partner has not entered into any employment agreements with any of our executive officers. There are no formal severance plans in place for any employees in the event of termination of employment, or a change in control of the Partnership. When an employee terminates employment with the Partnership, they are entitled to a cash payment for the amount of unused vacation hours at the date of their termination.

Compensation of Directors

General — On February 19, 2008, the board of directors of the General Partner approved a compensation package for directors who are not officers or employees of affiliates of the General Partner, or Non-Employee Directors. Members of the board who are also officers or employees of affiliates of the General Partner do not receive additional compensation for serving on the board. The board approved the payment to each Non-Employee Director of an annual compensation package containing the following: (1) a $40,000 retainer; (2) a board meeting fee of $1,250 for each board meeting attended; (3) a telephonic board meeting fee of $500 for each telephonic meeting attended; and (4) an annual grant of 1,000 phantom LPUs that have a six month vesting period. The directors also receive DERs, based on the number of units awarded, which are paid in cash on a quarterly basis. The phantom LPUs will be paid in units upon vesting.

Our directors will also be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors and committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Committees — The chairman of the audit committee of the board will receive an annual retainer of $20,000 and the members of the audit committee will receive $1,500 for each audit committee meeting attended. The chairman of the special committee of the board will likewise receive an annual retainer of $20,000 and the members of the special committee will receive $1,250 for each special committee meeting attended. Finally, the Non-Employee Director members of the compensation committee will receive $1,250 for each compensation committee meeting attended.

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Following is the compensation of the General Partner's Non-Employee Directors for the year ended December 31, 2007:

Name	Fees Earned or Paid in Cash	LPU Awards(e)	DERs	Total
Milton Carroll(a)	$ 20,000	$ —	$ —	$ 20,000
Derrill Cody(b)	$ 42,500	$ 41,450	$ 4,178	$ 88,128
Paul F. Ferguson, Jr.	$ 84,500	$ 66,975	$ 4,178	$ 155,653
Frank A. McPherson	$ 85,000	$ 66,975	$ 4,178	$ 156,153
Jim W. Mogg(c)	$ 40,000	$ —	$ —	$ 40,000
Thomas C. Morris	$ 63,000	$ 66,975	$ 4,178	$ 134,153
Stephen R. Springer(d)	$ 28,000	$ 19,146	$ 540	$ 47,686

(a) Mr. Carroll resigned from the board of directors of the General Partner effective December 20, 2006. The $20,000 represents the remaining amount owed for service to our board of directors in 2006 that was paid in 2007.

(b) Mr. Cody resigned from the board of directors of the General Partner effective November 12, 2007.

(c) Mr. Mogg resigned as Chairman of the board of directors of the General Partner effective April 30, 2007.

(d) Mr. Springer was appointed to the board of directors of the General Partner effective July 11, 2007.

(e) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes, in accordance with the provisions of SFAS 123R, and include amounts from awards granted in conjunction with our LTIP during 2007 and 2006. See Note 13 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

On November 29, 2006, the board of directors of the General Partner approved a compensation package for Jim W. Mogg, the former chairman of the board of directors. Mr. Mogg, who retired from Duke Energy Corporation in September 2006, received an annual retainer of $120,000, which was prorated for 2007 and 2006. Mr. Mogg was not eligible for additional compensation for attending board meetings or committee meetings that our other Non-Employee Directors are eligible to receive. Mr. Mogg was also the compensation committee chair. He received no additional compensation for serving in that capacity during 2007 and 2006. Mr. Mogg retired from the board of directors of the General Partner effective April 30, 2007, at which time Mr. Fred J. Fowler assumed the responsibilities of the Chairman of the board of directors and the compensation committee.

Mr. Cody was a member of the compensation committee. The value of Mr. Cody's phantom LPU awards, calculated in accordance with the provisions of SFAS 123R, was $22,331, as of the date of his resignation.

Mr. Ferguson is the audit committee chair and a member of the special committee.

Mr. McPherson was the special committee chair, and is a member of the audit committee and the compensation committee.

Mr. Morris is a member of the audit committee and the special committee.

Mr. Springer is the special committee chair, and is a member of the audit committee and the special committee.

The total grant date fair value of phantom LPU awards for the Non-Employee Directors for 2007 was $194,515. At December 31, 2007, Messrs. Ferguson, McPherson and Morris each had 1,333 phantom IPO LPUs outstanding and Mr. Springer had 500 phantom LPUs outstanding, related to awards granted in 2007 and 2006.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters***

The following table sets forth the beneficial ownership of our units and the related transactions held by:

- each person who beneficially owns 5% or more of our outstanding units as of March 3, 2008;
- all of the directors of DCP Midstream GP, LLC;
- each Named Executive Officer of DCP Midstream GP, LLC; and
- all directors and executive officers of DCP Midstream GP, LLC as a group.

Percentage of total common and subordinated units beneficially owned is based on 20,411,754 common units and 3,571,429 subordinated units outstanding.

Name of Beneficial Owner(a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
DCP LP Holdings, LP(b)(1)	4,675,022	22.9%	3,571,429	100%	34.4%
Fiduciary Asset Management, L.L.C.(c)	1,028,030	5.0%	—	—	4.3%
Lehman Brothers Holdings Inc.(d)	1,660,548	8.1%	—	—	6.9%
Mark A. Borer	33,001	*	—	—	*
Thomas E. Long	23,401	*	—	—	*
Michael S. Richards	3,501	*	—	—	*
Greg K. Smith	6,101	*	—	—	*
Fred J. Fowler	1,000	*	—	—	*
Paul F. Ferguson, Jr.	2,668	*	—	—	*
Frank A. McPherson	9,668	*	—	—	*
Thomas C. Morris	6,668	*	—	—	*
Stephen R. Springer	500	*	—	—	*
All directors and executive officers as a group (9 persons)	86,508	*	—	—	*

* Less than 1%.

(a) Unless otherwise indicated, the address for all beneficial owners in this table is 370 17th Street, Suite 2775, Denver, Colorado 80202.

(b) DCP Midstream, LLC is the ultimate parent company of DCP LP Holdings, LP and may, therefore, be deemed to beneficially own the units held by DCP LP Holdings, LP. DCP Midstream, LLC disclaims beneficial ownership of all of the units owned by DCP LP Holdings, LP. The address of DCP LP Holdings, LP and DCP Midstream, LLC is 370 17th Street, Suite 2500, Denver, Colorado 80202.

(c) As set forth in a Schedule 13G filed on September 19, 2007. The address of Fiduciary Asset Management, L.L.C. is 8112 Maryland Avenue, Suite 400, St. Louis, MO 63105. Fiduciary Asset Management, L.L.C. acts as an investment sub-advisor to certain closed-end investment companies, as well as to private individuals, some of whom may be deemed to be beneficial owners.

(d) As set forth in a Schedule 13G filed on February 13, 2008. Lehman Brothers MLP Opportunity Fund LP, or LB MLP Fund, is the actual owner of the units, however, as Lehman Brothers MLP Opportunity Associates LP is the general partner of LB MLP Fund and is wholly-owned by Lehman Brothers MLP Opportunity Associates LLC, which is wholly-owned by Lehman Brothers Holdings Inc., these entities may be deemed to beneficially own the units held by LB MLP Fund. The address of these entities is 745 Seventh Avenue, New York, NY.

Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2007.

	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (1) (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by unitholders	—	$ —	—
Equity compensation plans not approved by unitholders	—	—	782,841
Total	—	$ —	782,841

(1) The long-term incentive plan currently permits the grant of awards covering an aggregate of 850,000 units. For more information on our long-term incentive plan, which did not require approval by our limited partners, refer to Item 11. "Executive Compensation — Components of Compensation."

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

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our formation, ongoing operation, and liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm's-length negations.

Operational Stage:	
Distributions of Available Cash to our General Partner and its affiliates	We will generally make cash distributions to the unitholders and to our General Partner, in accordance with their pro rata interest. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our General Partner will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level. Our current distribution level exceeds the highest incentive distribution level.
Payments to our General Partner and its affiliates	We reimburse DCP Midstream, LLC and its affiliates $9.7 million per year, adjusted annually by changes in the Consumer Price Index, for the provision of various general and administrative services for our benefit. For further information regarding the reimbursement, please see the "Omnibus Agreement" section below.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage:	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Omnibus Agreement

The employees supporting our operations are employees of DCP Midstream, LLC. We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering.

Following is a summary of the fees we anticipate incurring in 2008 under the Omnibus Agreement and the effective date for these fees:

Terms	Effective Date	Fee (Millions)
Annual fee	2006	$ 5.1
Wholesale propane logistics business	November 2006	2.0
Southern Oklahoma	May 2007	0.2
Discovery	July 2007	0.2
Additional services	August 2007	0.6
MEG	August 2007	1.6
Total		$ 9.7

All of the fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

The Omnibus Agreement also addresses the following matters:

- DCP Midstream, LLC's obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of December 7, 2005 until the earlier of December 7, 2010 or when we obtain an investment grade credit rating from either Moody's Investor Services, Inc. or Standard & Poor's Ratings Group with respect to any of our unsecured indebtedness; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption "Contracts with Affiliates."

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described below, will be terminable by DCP Midstream, LLC at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us, our general partner (DCP Midstream GP, LP) or our General Partner (DCP Midstream GP, LLC).

Competition

None of DCP Midstream, LLC nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either our partnership agreement or the Omnibus Agreement, from competing with us. DCP

Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify us until December 7, 2008 against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DCP Midstream, LLC's maximum liability for this indemnification obligation does not exceed $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including pre-closing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the post-closing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC's indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake Pipe Line Company, or Black Lake, associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through June 2008. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Reimbursements of these expenses from DCP Midstream, LLC were not significant and were recognized by us as capital contributions.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC will indemnify us until October 31, 2008 for any breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, DCP Midstream, LLC agreed to indemnify us until October 31, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until October 31, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing, agreed to indemnify us until October 31, 2010 if certain contractual matters result in a claim, and agreed to indemnify us indefinitely for breaches of the agreement. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $680,000 and is subject to a maximum liability of $6.8 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, DCP Midstream, LLC will indemnify us until July 1, 2008 for the breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us until July 1, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until July 1, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels, and agreed to indemnify us indefinitely for breaches of the agreement and certain existing claims. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisition of certain subsidiaries of MEG, DCP Midstream will indemnify us following the closing on August 29, 2007 for any breach of the representations and warranties made under the acquisition agreement and certain other matters associated with these assets. DCP Midstream agreed to indemnify us until August 29, 2008 for any breach of the representations and warranties (except certain corporate related matters that survive indefinitely), and indefinitely for breaches of the agreement.

Contracts with Affiliates

We charge transportation fees, sell a portion of our residue gas and NGLs to, and purchase raw natural gas and NGLs from, DCP Midstream, LLC, ConocoPhillips, and their respective affiliates. Management anticipates continuing to purchase and sell these commodities to DCP Midstream, LLC, ConocoPhillips and their respective affiliates in the ordinary course of business.

Natural Gas Gathering and Processing Arrangements

We have a fee-based contractual relationship with ConocoPhillips, which includes multiple contracts, pursuant to which ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest to our Ada, Minden and Pelico systems under multiple agreements that have terms of up to five years and are market based. These agreements provide for the gathering, processing and transportation services at our Ada and Minden gathering and processing systems and the Pelico system. At our Ada gathering and processing system, we collect fees from ConocoPhillips for gathering and compressing the natural gas from the wellhead or receipt point and processing the natural gas at the Ada processing plant. At our Minden gathering and processing system, we purchase natural gas from ConocoPhillips at the wellhead or receipt point, transport the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs at index prices based on published index market prices. At our Pelico system, we collect fees for compression and transportation services. Please read Item 1. “Business — Natural Gas Services Segment — Customers and Contracts” and Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.” One of these arrangements is set forth in a natural gas gathering agreement dated June 1, 1987, as amended, between DCP Assets Holding, LP (successor to the interest of Cornerstone Natural Gas Company) and ConocoPhillips (successor to interest of Phillips Petroleum Company). We succeeded to the rights and obligations of DCP Assets Holding, LP under this agreement upon the closing of our initial public offering. Pursuant to this agreement, we receive gathering and compression fees from ConocoPhillips with respect to natural gas produced by ConocoPhillips that we gather and compress in our Ada gathering system from wells located in a designated area of mutual interest located in northern Louisiana covering approximately 54 square miles. The fees we receive are based on market rates for these types of services. To date, ConocoPhillips has drilled and connected approximately 145 wells to our Ada gathering system pursuant to this contract. This agreement expires in 2011. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Merchant Arrangements

Under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC (DCP Midstream Marketing, LP) as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas primarily to third parties. In the case of certain industrial end-user customers, from time to time we may sell aggregated natural gas to a subsidiary of DCP Midstream, LLC, which in turn would resell natural gas to these customers. Under these arrangements, we expect that this subsidiary of DCP Midstream, LLC would make a profit on these sales. We have also entered into a contractual arrangement with a subsidiary of DCP Midstream, LLC that requires DCP Midstream, LLC to supply Pelico’s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. We also sell our NGLs at the Minden processing plant to a subsidiary of DCP Midstream, LLC (DCP NGL Services, LP) who then transports the NGLs on the Black Lake pipeline. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Transportation Arrangements

Effective December 2005, we entered into a long-term, fee-based contractual arrangement with a subsidiary of DCP Midstream, LLC (DCP NGL Services, LP) that provided that the DCP Midstream, LLC subsidiary will pay us to transport NGLs on our Seabreeze pipeline pursuant to a fee-based rate that will be applied to the volumes transported. Under this agreement, we are required to reserve sufficient capacity in the Seabreeze pipeline to ensure our ability to accept up to 38,000 Bbls/d of NGLs tendered by the DCP Midstream, LLC subsidiary each day prior to utilizing the excess capacity for our own use or for that of any third parties, and the DCP Midstream, LLC subsidiary is required to tender all NGLs processed at certain plants that it owns, controls or otherwise has an obligation to market for others. DCP Midstream, LLC historically is also the largest shipper on the Black Lake pipeline, primarily due to the NGLs delivered to it from our Minden processing plant. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Derivative Arrangements

We have entered into long-term natural gas and crude oil swap contracts whereby we receive a fixed price for natural gas and crude oil and we pay a floating price. DCP Midstream, LLC has issued guarantees to our counterparties in those transactions that were in effect at the time of our initial public offering. With this credit support, we have more favorable collateral terms than we would have otherwise received. For more information regarding our derivative activities and credit support provided by DCP Midstream, LLC, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

Other Agreements and Transactions with DCP Midstream, LLC

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by an NGL product dedication agreement with DCP Midstream, LLC.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to our initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $3.4 million during 2006 and $0.3 million during 2007, to reimburse us for the capital costs we incurred, primarily for growth capital projects.

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in

Discovery. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $0.3 million during 2007 to reimburse us for these capital projects.

Review, Approval or Ratification of Transactions with Related Persons

Our partnership agreement contains specific provisions that address potential conflicts of interest between the owner of our general partner and its affiliates, including DCP Midstream, on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our general partner will resolve the conflict. Our general partner may, but is not required to, seek the approval of such resolution from the special committee of the board of directors of our general partner, which is comprised of independent directors and acts as our conflicts committee. The partnership agreement provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or to our unitholders if the resolution of the conflict is:

- approved by the conflicts committee;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner does not seek approval from the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in the best interests of the partnership, unless the context otherwise requires.

In addition, our code of business ethics requires that all employees, including employees of affiliates of DCP Midstream who perform services for us and our general partner, avoid or disclose any activity that may interfere, or have the appearance of interfering, with their responsibilities to us.

Director Independence

Please see Item 10. “Directors, Executive Officers and Corporate Governance” for information about the independence of our general partner’s board of directors and its committees, which information is incorporated herein by reference in its entirety.

Item 14. ***Principal Accounting Fees and Services***

The following table presents fees for professional services rendered by Deloitte & Touche LLP, or Deloitte, our principal accountant, for the audit of our financial statements, and the fees billed for other services rendered by Deloitte:

Type of Fees	Year Ended December 31, 2007	2006
	(Millions)	
Audit Fees(a)	$ 1.9	$ 2.5

(a) Audit Fees are fees billed by Deloitte for professional services for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our quarterly reports on Form 10-Q, services that are normally provided by Deloitte in connection with statutory and regulatory filings or engagements or any other service performed by Deloitte to comply with generally accepted auditing standards and include comfort and consent letters in connection with Securities and Exchange Commission filings and financing transactions.

Audit Committee Pre-Approval Policy

The audit committee pre-approves all audit and permissible non-audit services provided by the independent auditors on a case-by-case basis. These services may include audit services, audit-related services, tax services and other services. The audit committee does not delegate its responsibilities to pre-approve services performed by the independent auditor to management or to an individual member of the audit committee. The audit committee has, however, pre-approved audit related services that do not impair the independence of the independent auditors for up to $50,000 per engagement, and up to an aggregate of $200,000 annually, provided the audit committee is notified of such audit-related services in a timely manner. The audit committee may, however, from time to time delegate its authority to any audit committee member, who will report on the independent auditor services that were approved at the next audit committee meeting.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

Consolidated Financial Statements and Financial Statements Schedules included in this Item 15:

(a) Schedule II — Consolidated Valuation and Qualifying Accounts and Reserves

(b) Consolidated Financial Statements of Discovery Producer Services LLC and Financial Statements of DCP East Texas Holdings, LLC

(c) Exhibits

(a) ***Financial Statement Schedules***

DCP MIDSTREAM PARTNERS, LP

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts(a)	Deductions/ Other	Credit to Consolidated Statements of Operations	Balance at End of Period
			(Millions)			
December 31, 2007						
Allowance for doubtful accounts	$ 0.3	$ 0.8	$ 0.2	$ (0.1)	$ —	$ 1.2
Environmental	0.1	0.1	1.6	(0.1)	—	1.7
Other(b)	0.3	—	—	(0.3)	—	—
	$ 0.7	$ 0.9	$ 1.8	$ (0.5)	$ —	$ 2.9
December 31, 2006						
Allowance for doubtful accounts	$ 0.3	$ 0.3	$ —	$ (0.3)	$ —	$ 0.3
Environmental	0.1	—	—	—	—	0.1
Other(b)	—	0.3	—	—	—	0.3
	$ 0.4	$ 0.6	$ —	$ (0.3)	$ —	$ 0.7
December 31, 2005						
Allowance for doubtful accounts	$ 0.3	$ 0.1	$ —	$ —	$ (0.1)	$ 0.3
Environmental	—	0.2	—	(0.1)	—	0.1
Other(b)	1.3	—	—	(1.3)	—	—
	$ 1.6	$ 0.3	$ —	$ (1.4)	$ (0.1)	$ 0.4

(a) Related to acquisition of certain subsidiaries of Momentum Energy Group, Inc.

(b) Principally consists of other contingency liabilities, which are included in other current liabilities.

(b) ***Financial Statements***

Discovery Producer Services LLC

Consolidated Financial Statements

For the Years Ended December 31, 2007, 2006 and 2005

Report of Independent Registered Public Accounting Firm

To the Management Committee of
Discovery Producer Services LLC

We have audited the accompanying consolidated balance sheets of Discovery Producer Services LLC as of December 31, 2007 and 2006, and the related consolidated statements of income, members' capital, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Discovery Producer Services LLC at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As described in Note 4, effective December 31, 2005, Discovery Producer Services LLC adopted Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2008

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2007	2006 (In thousands)	2005
Revenues:			
Product sales:			
Affiliate	$ 216,889	$ 148,385	$ 70,848
Third-party	5,251	—	4,271
Gas and condensate transportation services:			
Affiliate	979	3,835	2,104
Third-party	15,553	14,668	13,302
Gathering and processing services:			
Affiliate	3,092	8,605	3,912
Third-party	17,767	19,473	25,806
Other revenues	1,141	2,347	2,502
Total revenues	260,672	197,313	122,745
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	93,722	66,890	19,103
Third-party	61,982	52,662	45,364
Operating and maintenance expenses:			
Affiliate	5,579	5,276	3,739
Third-party	23,409	17,773	6,426
Depreciation and accretion	25,952	25,562	24,794
Taxes other than income	1,330	1,114	1,151
General and administrative expenses — affiliate	2,280	2,150	2,053
Other (income) expense, net	534	283	(33)
Total costs and expenses	214,788	171,710	102,597
Operating income	45,884	25,603	20,148
Interest income	(1,799)	(2,404)	(1,685)
Foreign exchange (gain) loss	(388)	(2,076)	1,005
Income before cumulative effect of change in accounting principle	48,071	30,083	20,828
Cumulative effect of change in accounting principle	—	—	(176)
Net income	$ 48,071	$ 30,083	$ 20,652

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 38,509	$ 37,583
Trade accounts receivable:		
Affiliate	22,467	11,986
Other	5,847	6,838
Insurance receivable	5,692	12,623
Inventory	483	576
Other current assets	5,037	4,235
Total current assets	78,035	73,841
Restricted cash	6,222	28,773
Property, plant, and equipment, net	368,228	355,304
Total assets	$ 452,485	$ 457,918
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities:		
Accounts payable:		
Affiliate	$ 8,106	$ 7,017
Other	17,617	23,619
Accrued liabilities	6,439	5,119
Deposit held for construction	—	3,322
Other current liabilities	1,658	1,483
Total current liabilities	33,820	40,560
Noncurrent accrued liabilities	12,216	3,728
Commitments and contingent liabilities (Note 7)		
Members' capital	406,449	413,630
Total liabilities and members' capital	$ 452,485	$ 457,918

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2007	2006 (In thousands)	2005
OPERATING ACTIVITIES:			
Net income	$ 48,071	$ 30,083	$ 20,652
Cumulative effect of change in accounting principle	—	—	176
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	25,952	25,562	24,794
Net Loss on disposal of equipment	603	—	—
Cash provided (used) by changes in assets and liabilities:			
Trade accounts receivable	(9,389)	26,599	(35,263)
Insurance receivable	6,931	(12,147)	(476)
Inventory	93	348	(84)
Other current assets	(802)	(1,911)	(1,012)
Accounts payable	(7,540)	(6,062)	29,355
Accrued liabilities	1,320	(1,086)	(7,992)
Other current liabilities	(3,147)	2,070	664
Net cash provided by operating activities	62,092	63,456	30,814
INVESTING ACTIVITIES:			
Decrease (increase) in restricted cash	22,551	15,786	(44,559)
Property, plant, and equipment:			
Capital expenditures	(31,739)	(33,516)	(12,906)
Proceeds from sale of property, plant and equipment	649	—	—
Change in accounts payable — capital expenditures	2,625	568	(8,532)
Net cash used by investing activities	(5,914)	(17,162)	(65,997)
FINANCING ACTIVITIES:			
Distributions to members	(59,172)	(43,598)	(46,964)
Capital contributions	3,920	13,509	48,303
Net cash (used) provided by financing activities	(55,252)	(30,089)	1,339
Increase (decrease) in cash and cash equivalents	926	16,205	(33,844)
Cash and cash equivalents at beginning of period	37,583	21,378	55,222
Cash and cash equivalents at end of period	$ 38,509	$ 37,583	$ 21,378

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED STATEMENT OF MEMBERS' CAPITAL

	Williams Energy, L.L.C.	Williams Partners Operating LLC	DCP Assets Holding, LP	Eni BB Pipelines LLC	Total
			(In thousands)		
Balance at December 31, 2004	$ 195,822	$ —	$ 130,540	$ 65,283	$ 391,645
Contributions	16,269	24,400	7,634	—	48,303
Distributions	(30,030)	(1,280)	(15,654)	—	(46,964)
Net income	8,063	4,651	6,909	1,029	20,652
Sale of Eni 16.67% interest to Williams Energy L.L.C.	66,312	—	—	(66,312)	—
Sale of Williams Energy, L.L.C.'s 40% interest to Williams Partners Operating LLC	(142,761)	142,761	—	—	—
Sale of Williams Energy, L.L.C.'s 6.67% interest to DCP Assets Holding, LP	(25,869)	—	25,869	—	—
Balance, December 31, 2005	87,806	170,532	155,298	—	413,636
Contributions	800	1,600	11,109	—	13,509
Distributions	(10,798)	(16,400)	(16,400)	—	(43,598)
Net income	6,017	12,033	12,033	—	30,083
Balance at December 31, 2006	83,825	167,765	162,040	—	413,630
Contributions	—	—	3,920	—	3,920
Distributions	(7,233)	(28,270)	(23,669)	—	(59,172)
Net income	2,602	26,241	19,228	—	48,071
Sale of Williams Energy, L.L.C.'s 20% interest to Williams Partners Operating LLC	(79,194)	79,194	—	—	—
Balance at December 31, 2007	$ —	$ 244,930	$ 161,519	$ —	$ 406,449

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Description of Business

Our company consists of Discovery Producer Services LLC, or DPS, a Delaware limited liability company formed on June 24, 1996, and its wholly owned subsidiary, Discovery Gas Transmission LLC, or DGT, a Delaware limited liability company also formed on June 24, 1996. DPS was formed for the purpose of constructing and operating a 600 million cubic feet per day (MMcf/d) cryogenic natural gas processing plant near Larose, Louisiana and a 32,000 barrel per day (bpd) natural gas liquids fractionator plant near Paradis, Louisiana. DGT was formed for the purpose of constructing and operating a natural gas pipeline from offshore deep water in the Gulf of Mexico to DPS's gas processing plant in Larose, Louisiana. The pipeline has a design capacity of 600 MMcf/d and consists of approximately 173 miles of pipe. DPS has since connected several laterals to the DGT pipeline to expand its presence in the Gulf. Herein, DPS and DGT are collectively referred to in the first person as "we," "us" or "our" and sometimes as "the Company".

Until April 14, 2005, we were owned 50% by Williams Energy, L.L.C. (a wholly owned subsidiary of The Williams Companies, Inc.), 33.33% by DCP Assets, LP (DCP) formerly Duke Energy Field Services, LLC, and 16.67% by Eni BB Pipeline, LLC (Eni). Williams Energy, L.L.C. is our operator. Herein, The Williams Companies, Inc. and its subsidiaries are collectively referred to as "Williams."

On April 14, 2005, Williams acquired the 16.67% ownership interest in us, which was previously held by Eni. As a result, we became 66.67% owned by Williams and 33.33% owned by DCP.

On August 23, 2005, Williams Partners Operating LLC (a wholly owned subsidiary of Williams Partners L.P. (WPZ) acquired a 40% interest in us, which was previously held by Williams. In connection with this acquisition, Williams, DCP and WPZ amended our limited liability company agreement including provisions for (1) quarterly distributions of available cash, as defined in the amended agreement and (2) pursuit of capital projects for the benefit of one or more of our members when there is not unanimous consent. On December 22, 2005, DCP acquired a 6.67% interest in us, which was previously held by Williams. On June 28, 2007, WPZ acquired an additional 20% interest in us from Williams. At December 31, 2007, we are owned 60% by WPZ and 40% by DCP.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation. The consolidated financial statements have been prepared based upon accounting principles generally accepted in the United States and include the accounts of DPS and its wholly owned subsidiary, DGT. Intercompany accounts and transactions have been eliminated.

Reclassifications. Certain prior year amounts have been reclassified to conform with the current year presentation.

Use of Estimates. The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Estimates and assumptions used in the calculation of asset retirement obligations are, in the opinion of management, significant to the underlying amounts included in the consolidated financial statements. It is reasonably possible that future events or information could change those estimates.

Cash and Cash Equivalents. Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with maturities of three months or less when acquired.

Trade Accounts Receivable. Trade accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue that generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of the customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. There was no allowance for doubtful accounts at December 31, 2007 and 2006.

Insurance Receivable. Expenditures incurred for the repair of the pipeline and onshore facilities damaged by Hurricane Katrina in 2005 and damage to the Tahiti steel catenary riser (SCR), which are probable of recovery when incurred, are recorded as insurance receivable. Expenditures up to the insurance deductible and amounts subsequently determined not to be recoverable are expensed.

Gas Imbalances. In the course of providing transportation services to customers, DGT may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. This results in gas transportation imbalance receivables and payables which are recovered or repaid in cash, based on market-based prices, or through the receipt or delivery of gas in the future. Imbalance receivables and payables are included in Other current assets and Other current liabilities in the Consolidated Balance Sheets. Imbalance receivables are valued based on the lower of the current market prices or current cost of natural gas in the system. Imbalance payables are valued at current market prices. Settlement of imbalances requires agreement between the pipelines and shippers as to allocations of volumes to specific transportation contracts and the timing of delivery of gas based on operational conditions. In accordance with its tariff, DGT is required to account for this imbalance (cash-out) liability/receivable and refund or invoice the excess or deficiency when the cumulative amount exceeds $400,000. To the extent that this difference, at any year end, is less than $400,000, such amount would carry forward and be included in the cumulative computation of the difference evaluated at the following year end.

Inventory. Inventory includes fractionated products at our Paradis facility and is carried at the lower of cost or market.

Restricted Cash. Restricted cash within non-current assets relates to escrow funds contributed by our members for the construction of the Tahiti pipeline lateral expansion. The restricted cash is classified as non-current because the funds will be used to construct a long-term asset. The restricted cash is primarily invested in short-term money market accounts with financial institutions.

Property, Plant, and Equipment. Property, plant, and equipment are carried at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values. The natural gas and natural gas liquids maintained in the pipeline facilities necessary for their operation (line fill) are included in property, plant, and equipment.

Depreciation of DPS's facilities and equipment is computed primarily using the straight-line method with 25-year lives. Depreciation of DGT's facilities and equipment is computed using the straight-line method with 15-year lives.

We record an asset and a liability equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in operating income.

Revenue Recognition. Revenue for sales of products are recognized in the period of delivery and revenues from the gathering, transportation and processing of gas are recognized in the period the service is provided based on contractual terms and the related natural gas and liquid volumes. DGT is subject to Federal Energy Regulatory Commission (FERC) regulations, and accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending cases. DGT records rate refund liabilities considering regulatory proceedings by DGT and other third parties, advice of counsel, and estimated total exposure as discounted and risk weighted, as well as collection and other risks. There were no rate refund liabilities accrued at December 31, 2007 or 2006.

Impairment of Long-Lived Assets. We evaluate long-lived assets for impairment on an individual asset or asset group basis when events or changes in circumstances indicate that, in our management's judgment, the carrying value of such assets may not be recoverable. When such a determination has been made, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether the carrying value is recoverable. If the carrying value is not recoverable, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Accounting for Repair and Maintenance Costs. We expense the cost of maintenance and repairs as incurred. Expenditures that enhance the functionality or extend the useful lives of the assets are capitalized and depreciated over the remaining useful life of the asset.

Income Taxes. For federal tax purposes, we have elected to be treated as a partnership with each member being separately taxed on its ratable share of our taxable income. This election, to be treated as a pass-through entity, also applies to our wholly owned subsidiary, DGT. Therefore, no income taxes or deferred income taxes are reflected in the consolidated financial statements.

Foreign Currency Transactions. Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transaction gains or losses which are reflected in the Consolidated Statements of Income.

Recent Accounting Standards. In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements". This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In December 2007, the FASB issued proposed FASB Staff Position No. FAS 157-b deferring the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). SFAS No. 157 requires two distinct transition approaches; (i) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (ii) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable. On January 1, 2008, we adopted SFAS No. 157 with no impact to our Consolidated Financial Statements. SFAS No. 157 expands disclosures about assets and liabilities measured at fair value on a recurring basis effective beginning with the first quarter 2008 reporting.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115". SFAS No. 159 establishes a fair value option permitting entities to elect to measure eligible financial instruments and certain other items at fair value. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, is irrevocable and is applied only to the entire instrument. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007, and should not be applied retrospectively to fiscal years beginning prior to the effective date. On the adoption date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. Subsequent to

January 1, 2008, the fair value option can only be elected when a financial instrument or certain other item is entered into. On January 1, 2008, we adopted SFAS No. 159 but did not elect the fair value option for any existing eligible financial instruments or other items.

Note 3. Related Party Transactions

We have various business transactions with our members and subsidiaries and affiliates of our members. Revenues include the following:

- sales to Williams of NGLs to which we take title and excess gas at current market prices for the products,
- processing and sales of natural gas liquids and transportation of gas and condensate for DCP's affiliates, Texas Eastern Corporation and ConocoPhillips Company,
- and processing and transportation of gas and condensate for Eni.

The following table summarizes these related-party revenues during 2007, 2006 and 2005.

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Williams	$ 217,012	$ 148,543	$ 70,848
Texas Eastern Corporation	3,912	12,282	2,663
Eni*	—	—	2,830
ConocoPhillips	36	—	523
Total	$ 220,960	$ 160,825	$ 76,864

* Through April 14, 2005

We have no employees. Pipeline and plant operations are performed under operation and maintenance agreements with Williams. Most costs for materials, services and other charges are third-party charges and are invoiced directly to us. Operating and maintenance expenses— affiliate includes the following:

- direct payroll and employee benefit costs incurred on our behalf by Williams,
- and rental expense resulting from a 10-year leasing agreement for pipeline capacity from Texas Eastern Transmission, LP (an affiliate of DCP), as part of our market expansion project which began in June 2005.

Product costs and shrink replacement— affiliate includes natural gas purchases from Williams for fuel and shrink requirements made at market rates at the time of purchase.

General and administrative expenses — affiliate includes a monthly operation and management fee paid to Williams to cover the cost of accounting services, computer systems and management services provided to us.

We also pay Williams a project management fee to cover the cost of managing capital projects. This fee is determined on a project by project basis and is capitalized as part of the construction costs. A summary of the payroll costs and project fees charged to us by Williams and capitalized are as follows:

	Years Ended December 31,		
	2007	2006	2005
	(In thousands)		
Capitalized labor	$ 222	$ 373	$ 115
Capitalized project fee	651	538	351
	$ 873	$ 911	$ 466

Note 4. Property, Plant, and Equipment

Property, plant, and equipment consisted of the following at December 31, 2007 and 2006:

	Years Ended December 31,	
	2007	2006
	(In thousands)	
Property, plant, and equipment:		
Construction work in progress	$ 66,550	$ 37,259
Buildings	4,950	4,434
Land and land rights	2,491	2,491
Transportation lines	311,368	303,283
Plant and other equipment	200,722	200,990
Total property, plant, and equipment	586,081	548,457
Less accumulated depreciation	217,853	193,153
Net property, plant, and equipment	$ 368,228	$ 355,304

Commitments for construction and acquisition of property, plant, and equipment for the Tahiti pipeline lateral expansion are approximately $9 million at December 31, 2007.

Effective December 31, 2005, we adopted Financial Accounting Standards Board Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations.” This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability’s fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. As required by the new standard, we reassessed the estimated remaining life of all our assets with a conditional ARO. We recorded additional liabilities totaling $327,000 equal to the present value of expected future asset retirement obligations at December 31, 2005. The liabilities are slightly offset by a $151,000 increase in property, plant, and equipment, net of accumulated depreciation, recorded as if the provisions of the Interpretation had been in effect at the date the obligation was incurred. The net $176,000 reduction to earnings is reflected as a cumulative effect of a change in accounting principle for the year ended 2005.

Our obligations relate primarily to our offshore platform and pipelines and our onshore processing and fractionation facilities. At the end of the useful life of each respective asset, we are legally or contractually obligated to dismantle the offshore platform, properly abandon the offshore pipelines, remove the onshore facilities and related surface equipment and restore the surface of the property.

A rollforward of our asset retirement obligation for 2007 and 2006 is presented below.

	Years Ended December 31, 2007	2006
	(In thousands)	
Balance at January 1	$ 3,728	$ 1,121
Accretion expense	422	135
Estimate revisions	7,554	2,472
Liabilities incurred	414	—
Balance at December 31	$ 12,118	$ 3,728

Note 5. Leasing Activities

We lease the land on which the Paradis fractionator plant and the Larose processing plant are located. The initial term of each lease is 20 years with renewal options for an additional 30 years. We entered into a ten-year leasing agreement for pipeline capacity from Texas Eastern Transmission, LP, as part of our market expansion project which began in June 2005. The lease includes renewal options and options to increase capacity which would also increase rentals. The future minimum annual rentals under these non-cancelable leases as of December 31, 2007 are payable as follows:

	(In thousands)
2008	$ 858
2009	858
2010	858
2011	858
2012	858
Thereafter	2,388
	$ 6,678

Total rent expense for 2007, 2006 and 2005, including a cancelable platform space lease and month-to-month leases, was $1.4 million, $1.4 million and $1.1 million, respectively.

Note 6. Financial Instruments and Concentrations of Credit Risk

Financial Instruments Fair Value

We used the following methods and assumptions to estimate the fair value of financial instruments:

Cash and cash equivalents. The carrying amounts reported in the consolidated balance sheets approximate fair value due to the short-term maturity of these instruments.

Restricted cash. The carrying amounts reported in the consolidated balance sheets approximate fair value as these instruments have interest rates approximating market.

	2007 Carrying Amount	2007 Fair Value	2006 Carrying Amount	2006 Fair Value
	(In thousands)			
Cash and cash equivalents	$ 38,509	$ 38,509	$ 37,583	$ 37,583
Restricted cash	6,222	6,222	28,773	28,773

Concentrations of Credit Risk

Our cash equivalents and restricted cash consist of high-quality securities placed with various major financial institutions with credit ratings at or above AA by Standard & Poor's or Aa by Moody's Investor's Service.

At December 31, 2007 and 2006, substantially all of our customer accounts receivable result from gas transmission services for and natural gas liquids sales to our two largest customers. This concentration of customers may impact our overall credit risk either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly. Our credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables. We did not incur any credit losses on receivables during 2007 and 2006.

Major Customers. Williams accounted for approximately $217.0 million (83%), $149.0 million (75%), $70.8 million (58%) respectively, of our total revenues in 2007, 2006 and 2005.

Note 7. Rate and Regulatory Matters and Contingent Liabilities

Rate and Regulatory Matters. Annually, DGT files a request with the FERC for a lost-and-unaccounted-for gas percentage to be allocated to shippers for the upcoming fiscal year beginning July 1. On May 31, 2007, DGT filed to maintain a lost-and-unaccounted-for percentage of zero percent for the period July 1, 2007 to June 30, 2008 and to retain the 2006 net system gains of $1.8 million that are unrelated to the lost-and-unaccounted-for gas over recovered from its shippers. By Order dated June 28, 2007 the filing was approved. The approval was subject to a 30 day protest period, which passed without protest. As of December 31, 2007, and 2006, DGT has deferred amounts of $5.8 million and $4.4 million, respectively, included in current accrued liabilities in the accompanying Consolidated Balance Sheets representing amounts collected from customers pursuant to prior years' lost and unaccounted for gas percentage and unrecognized net system gains.

On November 25, 2003, the FERC issued Order No. 2004 promulgating new standards of conduct applicable to natural gas pipelines. On August 10, 2004, the FERC granted DGT a partial exemption allowing the continuation of DGT's current ownership structure and management subject to compliance with many of the other standards of conduct. On November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded Order No. 2004 as applied to interstate natural gas pipelines and their affiliates. On January 9, 2007, the FERC issued an Interim Rule. The Interim Rule re-promulgates, on an interim basis, the standards of conduct that were not challenged before the Court. The Interim Rule applies to the relationship between interstate natural gas pipelines and their marketing and brokering affiliates, but not necessarily to their other affiliates, such as gatherers, processors or exploration and production companies. On March 21, 2007 the FERC issued an Order on Clarification and Rehearing of the Interim Rule. The FERC clarified that the interim standards of conduct only apply to natural gas transmission providers that are affiliated with a marketing or brokering entity that conducts transportation transactions on such natural gas transmission provider's pipeline. Currently DGT's marketing or brokering affiliates do not conduct transmission transactions on DGT. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking to propose permanent regulations regarding the standards of conduct. Comments were due April 4, 2007. The FERC may enact a final rule at any time. At this stage, it cannot be determined how a final rule may or may not affect us (or DGT).

On November 16, 2007, DGT filed a petition for approval of settlement in lieu of a general rate change filing with FERC. FERC issued a Notice of DGT's filing setting a deadline for comments on November 27, 2007. One shipper, ExxonMobil, filed a protest. On December 3, DGT filed a response to ExxonMobil's protest. On December 18, ExxonMobil filed a Motion for Leave to Answer and Answer and DGT responded on December 20. On February 5, 2008 the FERC issued an order approving the settlement as to all parties except the protesting ExxonMobil Gas & Power Marketing Company. The order is subject to rehearing until March 6, 2008. The settlement is not final until the order is final and no longer subject to rehearing.

Pogo Producing Company. On January 16, 2006, DPS and DGT received notice of a claim by Pogo Producing Company (Pogo) relating to the results of a Pogo audit performed first in April 2004 and then continued through August 2005. Pogo claimed that DPS and DGT overcharged Pogo and its working interest owners approximately $600,000 relating to condensate transportation and handling during 2000 – 2005. The underlying agreements limit audit claims to a two-year period from the date of the audit. DPS and DGT disputed the validity of the claim. On November 2, 2007, the claim was settled for $300,000. In connection with the settlement, Pogo assigned production module equipment to us, and we assumed the associated asset retirement obligation. No gain or loss was recognized.

Environmental Matters. We are subject to extensive federal, state, and local environmental laws and regulations which affect our operations related to the construction and operation of our facilities. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. We have not been notified and are not currently aware of any noncompliance under the various environmental laws and regulations.

Other. We are party to various other claims, legal actions and complaints arising in the ordinary course of business. Litigation, arbitration and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our future financial position.

Note 8. Subsequent Events

On January 30, 2008, we made quarterly cash distributions totaling $28.0 million to our members.

DCP East Texas Holdings, LLC

Consolidated Financial Statements

For the Years Ended

December 31, 2007, 2006 and 2005

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP East Texas Holding, LLC (formerly the East Texas Midstream Business) (the "Company"), as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in partners' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule when considered with the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

The accompanying consolidated financial statements have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. Portions of certain expenses represent allocations made from, and are applicable to, DCP Midstream, LLC as a whole.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED BALANCE SHEETS
($ in millions)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4.8	$ —
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.5 million and $0.2 million, respectively	16.0	30.1
Affiliates	64.5	0.1
Other	0.8	0.8
Other	0.4	0.1
Total current assets	86.5	31.1
Property, plant and equipment, net	236.5	228.3
Total assets	$ 323.0	$ 259.4
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 53.6	$ 44.4
Affiliates	1.5	0.6
Other	2.9	2.6
Other	7.7	5.8
Total current liabilities	65.7	53.4
Deferred income taxes	1.7	1.8
Other long-term liabilities	0.5	0.5
Total liabilities	67.9	55.7
Commitments and contingent liabilities Partners' equity	255.1	203.7
Total liabilities and partners' equity	$ 323.0	$ 259.4

See accompanying notes to consolidated financial statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS
($ in millions)

	Years Ended December 31,		
	2007	2006	2005
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 179.8	$ 177.7	$ 164.7
Sales of natural gas, NGLs and condensate to affiliates	270.9	286.6	365.6
Transportation and processing services	22.2	21.9	17.1
Transportation and processing services to affiliates	0.1	0.3	0.3
Losses from non-trading derivative activity — affiliates	(0.1)	(1.1)	(1.7)
Total operating revenues	472.9	485.4	546.0
Operating costs and expenses:			
Purchases of natural gas and NGLs	357.8	376.0	418.8
Purchases of natural gas and NGLs from affiliates	1.1	9.3	25.3
Operating and maintenance expense	27.2	24.4	20.2
Depreciation expense	15.8	14.6	14.0
General and administrative expense	1.8	0.2	0.1
General and administrative expense — affiliate	10.3	11.3	9.8
Total operating costs and expenses	414.0	435.8	488.2
Operating income	58.9	49.6	57.8
Interest income	0.3	—	—
Income before income taxes	59.2	49.6	57.8
Income tax expense	0.7	1.8	—
Net income	$ 58.5	$ 47.8	$ 57.8

See accompanying notes to consolidated financial statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY
($ in millions)

Balance, January 1, 2005	$ 220.0
Net change in parent advances	(83.8)
Net income	57.8
Balance, December 31, 2005	194.0
Net change in parent advances	(38.1)
Net income	47.8
Balance, December 31, 2006	203.7
Net change in parent advances	(17.1)
Contributions	54.5
Distributions	(44.5)
Net income	58.5
Balance, December 31, 2007	$ 255.1

See accompanying notes to consolidated financial statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS
($ in millions)

	Year Ended December 31,		
	2007	2006	2005
OPERATING ACTIVITIES:			
Net income	$ 58.5	$ 47.8	$ 57.8
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation expense	15.8	14.6	14.0
Deferred income taxes	(0.1)	1.8	—
Other, net	(0.1)	0.1	0.1
Change in operating assets and liabilities which provided (used) cash:			
Accounts receivable	(50.6)	0.3	(16.9)
Accounts payable	10.2	(12.6)	33.1
Other current assets and liabilities	2.9	(1.0)	1.8
Other non-current assets and liabilities	—	(0.2)	(0.1)
Net cash provided by operating activities	36.6	50.8	89.8
INVESTING ACTIVITIES:			
Capital expenditures	(24.5)	(12.8)	(6.1)
Proceeds from sales of assets	—	0.1	0.1
Net cash used in investing activities	(24.5)	(12.7)	(6.0)
FINANCING ACTIVITIES:			
Net change in parent advances	(17.1)	(38.1)	(83.8)
Distributions	(44.5)	—	—
Contributions	54.3	—	—
Net cash used in financing activities	(7.3)	(38.1)	(83.8)
Net change in cash	4.8	—	—
Cash, beginning of period	—	—	—
Cash, end of period	$ 4.8	$ —	$ —

See accompanying notes to consolidated financial statements.

DCP EAST TEXAS HOLDINGS, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business and Basis of Presentation

DCP East Texas Holdings, LLC, or East Texas, we, our, or us, is a joint venture engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and natural gas liquids, or NGLs. Our operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 million cubic feet per day. The facility is connected to our 845 mile gathering system, as well as third party gathering systems. The complex is adjacent to our Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 billion cubic feet per day, acts as a key exchange point for the purchase and sale of residue gas.

East Texas is owned 75% by DCP Midstream, LLC, or Midstream, and 25% by DCP Midstream Partners, LP, or Partners. The consolidated financial statements include the accounts of East Texas and, prior to July 1, 2007, the operations, assets and liabilities contributed to us by Midstream, or the Business. This was a transaction between entities under common control; accordingly, our financial information includes the results for all periods presented. Midstream is a joint venture owned 50% by Spectra Energy Corp (which was spun off by Duke Energy Corporation on January 2, 2007) and 50% by ConocoPhillips. As of December 31, 2007, Midstream owns a 35% interest in Partners, including 100% of the general partner interest. Midstream directs our business operations. East Texas does not currently, and does not expect to, have any employees.

The consolidated financial statements include the accounts of East Texas and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The consolidated financial statements of the Business were prepared from the separate records maintained by Midstream and may not necessarily be indicative of the conditions that would have existed, or the results of operations, if the Business had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all the various assets comprising East Texas until July 1, 2007, Midstream's contributions and distributions are shown as net change in parent advances in lieu of contributions and distributions in the consolidated statements of changes in partners' equity. Transactions between East Texas and other Midstream operations have been identified in the consolidated financial statements as transactions between affiliates. In the opinion of management, all adjustments have been reflected that are necessary for a fair presentation of the consolidated financial statements.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents — Cash and cash equivalents includes all cash balances and highly liquid investments with an original maturity of three months or less.

Fair Value of Financial Instruments — The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts, due to the short-term nature of these instruments. Unrealized gains and losses on non-trading derivative instruments are recorded at fair value.

Accounting for Risk Management and Derivative Activities and Financial Instruments — Each derivative not qualifying as a normal purchase or normal sale exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings.

Our derivative activity includes normal purchase or normal sale contracts, and non-trading derivative instruments related to commodity prices. Normal purchase and normal sale contracts are accounted for under the accrual method and are reflected in the consolidated statements of operations in either sales or purchases upon settlement. Other commodity non-trading derivative instruments are accounted for under the mark-to-market method, whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in gains or losses from non-trading derivative activity — affiliates during the current period.

Valuation — When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Long-Lived Assets — We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Revenue Recognition — We generate the majority of our revenues from gathering, processing, compressing, transporting, and fractionating natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

We obtain access to raw natural gas and provide our midstream natural gas services principally under contracts that contain a combination of one or more of the following arrangements.

- *Fee-based arrangements* — Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, or transporting of natural gas. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase raw natural gas at the wellhead, or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of raw natural gas from the wellhead location to the delivery point. The revenue we earn is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.
- *Percent-of-proceeds/index arrangements* — Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.
- *Keep-whole arrangements* — Under the terms of a keep-whole processing contract, we gather raw natural gas from the producer for processing, market the NGLs and return to the producer residue natural gas with a British thermal unit, or Btu, content equivalent to the Btu content of the raw natural gas gathered. This arrangement keeps the producer whole to the thermal value of the raw natural gas received. Under these types of contracts, we are exposed to the "frac spread." The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices.

We recognize revenue for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract, executed by both us and the customer.
- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory,

delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectability is probable* — Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported as one transaction. We recognize revenues for non-trading derivative activity in the consolidated statements of operations as gains or losses from non-trading derivative activity — affiliates, including mark-to-market gains and losses and financial or physical settlement.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable — other as of December 31, 2007 and 2006 were imbalances totaling $0.8 million and $0.4 million, respectively. Included in the consolidated balance sheets as accounts payable — other as of December 31, 2007 and 2006 were imbalances totaling $2.9 million and $2.2 million, respectively

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities are included in the consolidated balances sheets as other current liabilities. Environmental liabilities included in the consolidated balance sheets as other current liabilities as of December 31, 2007 and 2006 were insignificant and $0.3 million, respectively.

Income Taxes — Deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities, and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realizability of deferred tax assets is assessed and, if necessary, a valuation allowance is recorded to write down the deferred tax assets to their realizable value. East Texas is a member of a consolidated group. We have calculated current and deferred income taxes as if we were a separate taxpayer.

We are treated as a pass-through entity for U.S. federal income tax purposes. As such, we do not directly pay federal income taxes. The Texas legislature replaced their franchise tax with a margin tax system in May 2006. As of 2007, we are subject to the Texas margin tax, which is treated as an income tax. Accordingly, we recorded a deferred tax liability and related expense in 2007 and 2006, related to the temporary differences that are expected to reverse in periods when the tax will apply.

3. Recent Accounting Pronouncements

Statement of Financial Accounting Standards, or SFAS, No. 141(R) "Business Combinations (revised 2007)," or SFAS 141(R) — In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

Statement of Financial Accounting Standards, or SFAS, No. 159, The Fair Value Option for Financial Assets and Financial Liabilities — including an amendment of FAS 115, or SFAS 159 — In February 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

SFAS No. 157, Fair Value Measurements, or SFAS 157 — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. We expect the cumulative effect after-tax impact to be insignificant as a result of adoption on January 1, 2008.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement 109, or FIN 48 — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a material impact on our consolidated results of operations, cash flows or financial position.

EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, or EITF 04-13 — In September 2005, the FASB ratified the EITF's consensus on Issue 04-13, which requires an entity to treat sales and purchases of inventory between the entity and the same counterparty as one transaction for purposes of applying APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, or APB 29, when such transactions are entered into in contemplation of each other. When such transactions are legally contingent on each other, they are considered to have been entered into in contemplation of each other. The EITF also agreed on other factors that should be considered in determining whether transactions have been entered into in contemplation of each other. EITF 04-13 is to be applied to new arrangements that we enter into after March 31, 2006. The impact of the adoption of EITF 04-13 for the year ended December 31, 2006 was a reduction of sales and purchases of approximately $44.3 million.

4. Agreements and Transactions with Affiliates

The employees supporting our operations are employees of Midstream. Costs incurred by Midstream on our behalf for salaries and benefits of operating personnel, as well as capital expenditures, maintenance and repair costs, and taxes have been directly allocated to us. Midstream also provides centralized corporate functions on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. Midstream records the accrued liabilities and prepaid expenses for most general and administrative expenses in its financial statements, including liabilities related to payroll, short and long-term incentive plans, employee retirement and medical plans, paid time off, audit, tax, insurance and other service fees. Through June 30, 2007, our share of those costs were allocated based on Midstream's proportionate investment (consisting of property, plant and equipment, equity method investment and intangibles) compared to our investment. In management's estimation, the allocation methodologies used through June 30, 2007 were reasonable and resulted in an allocation to us of our costs of doing business borne by Midstream.

Effective July 1, 2007, as part of the agreement with Midstream, we are required to reimburse Midstream for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, insurance, taxes and other direct, indirect, and allocable costs and expenses incurred by Midstream on our behalf. We also pay Midstream an annual fee for centralized corporate functions performed by Midstream on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. The agreement states that the fee for 2007 shall be $4.0 million as prorated from July 1 through December 31, 2007. For 2008, the fee is subject to adjustment for changes in the Consumer Price Index. After 2008, the fee shall be mutually agreed upon. If East Texas makes any acquisitions or otherwise expands prior to December 31, 2008, then the amount shall be reasonably increased.

Prior to July 1, 2007, we had no cash balances on the consolidated balances sheets. Up to that date, all of our cash management activity was performed by Midstream on our behalf, including collection of receivables, payment of payables, and the settlement of sales and purchases transactions with Midstream, which were recorded as parent advances and were included in parent equity on the accompanying consolidated balance sheets.

We currently, and anticipate to continue to, sell to Midstream, and purchase from and sell to ConocoPhillips, in the ordinary course of business. Midstream was a significant customer during the years ended December 31, 2007, 2006, and 2005.

Prior to December 31, 2006, we sold to and purchased from Duke Energy Corporation. On January 2, 2007, Duke Energy Corporation spun off their natural gas businesses, including their 50% ownership interest in Midstream, to Duke Energy shareholders. As a result of this transaction, Duke Energy Corporation's 50%

ownership interest in Midstream was transferred to Spectra Energy Corp. Consequently, Duke Energy Corporation is not considered a related party for reporting periods after January 2, 2007. We had no significant transactions with Spectra Energy Corp.

The following table summarizes transactions with affiliates :

	Year Ended December 31, 2007	2006	2005
		(Millions)	
DCP Midstream, LLC:			
Sales of natural gas, NGLs and condensate	$ 263.2	$ 276.3	$ 355.2
General and administrative expense	$ 10.3	$ 11.3	$ 9.8
Duke Energy Corporation:			
Sales of natural gas, NGLs and condensate	$ —	$ 6.6	$ 6.7
Purchases of natural gas and NGLs	$ —	$ 0.1	$ 3.8
ConocoPhillips:			
Sales of natural gas, NGLs and condensate	$ 7.7	$ 3.7	$ 3.7
Transportation and processing services	$ 0.1	$ 0.3	$ 0.3
Purchases of natural gas and NGLs	$ 1.1	$ 9.2	$ 21.5

We had accounts receivable and accounts payable with affiliates as follows:

	December 31, 2007	2006
	(Millions)	
DCP Midstream LLC:		
Accounts receivable	$ 64.5	$ —
Accounts payable	$ 1.5	$ —
ConocoPhillips:		
Accounts receivable	$ —	$ 0.1
Accounts payable	$ —	$ 0.6

Capital Project Reimbursement

In addition, Midstream has reimbursed us for work we performed on certain capital projects as defined in the Contribution Agreement. We received $3.4 million of capital reimbursements during the year ended December 31, 2007. Payment is treated as a contribution from Midstream.

Competition

Neither Midstream or Partners, nor any of their respective affiliates are restricted under the limited liability agreement from competing with us in other business opportunities, transactions, ventures, or other arrangements that may be competitive with or the same as us.

Indemnification

Effective upon closing on July 1, 2007, Midstream will indemnify us until July 1, 2008 for the breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us until

July 1, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until July 1, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain our assets that were formerly owned by Gulf South and UP Fuels, and agreed to indemnify us indefinitely for breaches of the agreement and certain existing claims. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

5. Property, Plant and Equipment

A summary of property, plant and equipment is as follows

	Depreciable Life	December 31, 2007	December 31, 2006
		(Millions)	
Gathering systems	15 – 30 Years	$ 78.9	$ 70.0
Processing plants	25 – 30 Years	218.5	218.4
Transportation	25 – 30 Years	40.0	34.3
General plant	3 – 5 Years	7.8	7.2
Construction work in progress		14.7	6.5
		359.9	336.4
Accumulated depreciation		(123.4)	(108.1)
Property, plant and equipment, net		$ 236.5	$ 228.3

Depreciation expense was $15.8 million, $14.6 million and $14.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

6. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts. The following summarizes the estimated fair value of financial instruments:

	December 31, 2007		December 31, 2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		(Millions)		
Accounts receivable	$ 81.3	$ 81.3	$ 31.0	$ 31.0
Accounts payable	$ 58.0	$ 58.0	$ 47.6	$ 47.6

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short term nature of these instruments or the stated rates approximating market rates.

7. Risk Management and Derivative Activities, Credit Risk and Financial Instruments

The only impact of our derivative activity was losses from non-trading derivative activity — affiliates of $0.1 million, $1.1 million and $1.7 million for the years ended December 31, 2007, 2006 and 2005, respectively.

We are exposed to market risks, including changes in commodity prices. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of the identified risks. In general, we attempt to mitigate risks related to the variability of future cash flows resulting from changes in applicable commodity prices. Midstream has a comprehensive risk management policy, or the Risk Management Policy, and a risk management committee, to monitor and manage market risks associated with commodity prices. Midstream's Risk Management Policy prohibits the use of derivative instruments for speculative purposes.

Commodity Price Risk — Our principal operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and sale of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs and natural gas. As an owner and operator of natural gas processing assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas, NGLs and condensate, and related products produced, processed or transported.

Credit Risk — We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of Midstream, national wholesale marketers, industrial end-users and gas-fired power plants. Our principal NGL customers include an affiliate of Midstream, producers and marketing companies. Concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under Midstream's corporate credit policy. Midstream's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow Midstream's credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with Midstream's credit policy and guidelines. The agreements also provide that the inability of counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a form satisfactory to us.

Commodity Non-Trading Derivative Activity — The sale of energy related products and services exposes us to the fluctuations in the market values of exchanged instruments. On a monthly basis, we may enter into non-trading derivative instruments in order to match the pricing terms to manage our purchase and sale portfolios. Midstream manages our marketing portfolios in accordance with their Risk Management Policy, which limits exposure to market risk.

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas or NGLs in future periods.

8. Asset Retirement Obligations

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. Accretion expense for the years ended December 31, 2007, 2006 and 2005 was not significant.

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation as December 31, 2007 and 2006 included in the consolidated balance sheets as other long-term liabilities was $0.5 million and $0.4 million, respectively.

9. Income Taxes

In May 2006, the State of Texas enacted a margin-based franchise tax law that replaced the existing franchise tax, commonly referred to as the Texas margin tax. The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. As a result of the change in Texas franchise law, our status in the state of Texas changed from non-taxable to taxable. Since the Texas margin tax is considered an income tax, in 2006 we recorded a non-current deferred tax liability of $1.8 million. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year. Accordingly, we recorded current tax expense for the Texas margin tax, beginning in 2007, of $0.8 million and a reduction in deferred taxes of $0.1 million.

Our effective tax rate differs from statutory rates primarily due to our being treated as a pass-through entity for United States income tax purposes, while being treated as a taxable entity in Texas.

10. Commitments and Contingent Liabilities

Litigation — We are not a party to any significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position, or cash flows.

Insurance — For the period August 2006 through August 2007, Midstream's insurance coverage was carried with an affiliate of ConocoPhillips and third party insurers. Prior to August 2006, Midstream carried a portion of their insurance coverage with an affiliate of Duke Energy Corporation. Effective in August 2007, insurance coverage is carried with third party insurers. Midstream's insurance coverage includes: (1) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) excess liability insurance above the established primary limits for commercial general liability and automobile liability insurance; and (5) property insurance covering the replacement value of all real and personal property damage, including damages arising from boiler and machinery breakdowns, windstorms, earthquake, flood damage and business interruption/extra expense. All coverages are subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

DCP EAST TEXAS HOLDINGS, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

A portion of the insurance costs described above are allocated by Midstream to us through the allocation methodology described in Note 4.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, or treating natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

11. Supplemental Cash Flow Information

	Year Ended December 31, 2007	2006 (Millions)	2005
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 0.9	$ 3.1	$ 0.6
Contributions related to environmental reserves retained by Midstream	$ 0.2	$ —	$ —

DCP EAST TEXAS HOLDINGS, LLC

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Deductions/ Other	Balance at End of Period
		(Millions)		
December 31, 2007				
Allowance for doubtful accounts	$ 0.2	$ 0.3	$ —	$ 0.5
Environmental	0.3	—	(0.3)	—
	$ 0.5	$ 0.3	$ (0.3)	$ 0.5
December 31, 2006				
Allowance for doubtful accounts	$ 0.1	$ 0.1	$ —	$ 0.2
Environmental	0.4	—	(0.1)	0.3
	$ 0.5	$ 0.1	$ (0.1)	$ 0.5
December 31, 2005				
Allowance for doubtful accounts	$ —	$ 0.1	$ —	$ 0.1
Environmental	—	0.4	—	0.4
	$ —	$ 0.5	$ —	$ 0.5

(c) *Exhibits*

A list of exhibits required by Item 601 of Regulation S-K to be filed as part of this report:

Exhibit Number	Description
10.1*	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.2*	Bridge Credit Agreement, dated May 9, 2007 among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.3*	Third Amendment to Omnibus Agreement, dated May 9, 2007, among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, and DCP Midstream Operating, LP (attached as Exhibit 99.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.4*	First Amendment to Credit Agreement, dated May 9, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.4 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.5*	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
10.6*	Common Unit Purchase Agreement, dated May 21, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
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10.8*	Common Unit Purchase Agreement, dated June 19, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.9*	Registration Rights Agreement, dated June 22, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 25, 2007).
10.10*	Amended and Restated Credit Agreement, dated June 21, 2007, among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association as Administrative Agent (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on June 27, 2007).
10.11*	Fourth Amendment to Omnibus Agreement, dated July 1, 2007, by and among DCP Midstream, LLC, DCP Midstream GP, LLC, DCP Midstream GP, LP, DCP Midstream Partners, LP, and DCP Midstream Operating, LP (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.12*	Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC, dated July 1, 2007, between DCP Midstream, LLC and DCP Assets Holding, LP (attached as Exhibit 10.3 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on July 2, 2007).
10.13*	Fifth Amendment to Omnibus Agreement dated August 7, 2007, among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP Form 10-Q (File No. 001-32678) filed with the Securities and Exchange Commission on August 9, 2007).
10.14*	Sixth Amendment to Omnibus Agreement, dated August 29, 2007, among DCP Midstream, LLC, DCP Midstream Partners, LP, DCP Midstream GP, LP, DCP Midstream GP, LLC, and DCP Midstream Operating, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).

Exhibit Number	Description
10.15*	Registration Rights Agreement, dated August 29, 2007, by and among DCP Midstream Partners, LP and the Purchasers listed therein (attached as Exhibit 10.2 to DCP Midstream Partners LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on September 5, 2007).
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23.1	Consent of Deloitte & Touche LLP on Consolidated Financial Statements and Financial Statement Schedule of DCP Midstream Partners, LP and the effectiveness of DCP Midstream Partners, LP's internal control over financial reporting.
23.2	Consent of Ernst & Young LLP on Consolidated Financial Statements of Discovery Producer Services LLC.
23.3	Consent of Deloitte & Touche LLP on Consolidated Financial Statements and Financial Statement Schedule of DCP East Texas Holdings, LLC.
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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 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Consolidated Balance Sheet of DCP Midstream GP, LP as of December 31, 2007.
99.2	Consolidated Balance Sheet of DCP Midstream, LLC as of December 31, 2007.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the 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, in the City of Denver, State of Colorado, on March 7, 2008.

DCP Midstream Partners, LP

By: DCP Midstream GP, LP
its General Partner

By: DCP Midstream GP, LLC
its General Partner

By: /s/ Mark A. Borer
Name: Mark A. Borer
Title: President and Chief Executive Officer

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POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS that each person whose signature appears below constitutes and appoints each of Mark A. Borer and Thomas E. Long as his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or in his name, place, and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this annual report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ Mark A. Borer Mark A. Borer	President, Chief Executive Officer and Director (Principal Executive Officer)	March 7, 2008
/s/ Thomas E. Long Thomas E. Long	Vice President and Chief Financial Officer (Principal Financial Officer)	March 7, 2008
/s/ Scott R. Delmoro Scott R. Delmoro	Chief Accounting Officer (Principal Accounting Officer)	March 7, 2008
/s/ Fred J. Fowler Fred J. Fowler	Chairman of the Board	March 7, 2008
/s/ Willie C.W. Chiang Willie C.W. Chiang	Director	March 7, 2008
/s/ Sigmund L. Cornelius Sigmund L. Cornelius	Director	March 7, 2008
/s/ Paul F. Ferguson, Jr. Paul F. Ferguson, Jr.	Director	March 7, 2008
/s/ Frank A. McPherson Frank A. McPherson	Director	March 7, 2008
/s/ Thomas C. Morris Thomas C. Morris	Director	March 7, 2008
/s/ Thomas C. O’Connor Thomas C. O’Connor	Director	March 7, 2008
/s/ Stephen R. Springer Stephen R. Springer	Director	March 7, 2008

EXHIBIT INDEX

Exhibit Number	Description
10.1*	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
10.2*	Bridge Credit Agreement, dated May 9, 2007 among DCP Midstream Operating, LP, DCP Midstream Partners, LP and Wachovia Bank, National Association (attached as Exhibit 99.2 to DCP Midstream Partners, LP's current report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
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99.1	Consolidated Balance Sheet of DCP Midstream GP, LP as of December 31, 2007.
99.2	Consolidated Balance Sheet of DCP Midstream, LLC as of December 31, 2007.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

The table below sets forth the calculation of Ratios of Earnings to Fixed Charges.

	DCP Midstream Partners, LP Year Ended December 31, (Millions)				
	2007	2006	2005	2004	2003
Earnings from continuing operations before fixed charges					
Pretax income (loss) from continuing operations before income or loss from equity method investments	$ (55.0)	$ 32.7	$ 47.4	$ 30.2	$ 16.3
Fixed charges	27.0	12.6	1.5	0.1	0.1
Distributed income of equity method investments	38.9	25.9	25.7	13.4	2.6
Less:					
Capitalized interest	(0.2)	(0.4)	—	—	—
Earnings from continuing operations before fixed charges	$ 10.7	$ 70.8	$ 74.6	$ 43.7	$ 19.0
Fixed charges					
Interest expense, net of capitalized interest	$ 26.0	$ 11.4	$ 0.8	$ —	$ —
Capitalized interest	0.2	0.4	—	—	—
Estimate of interest within rental expense	0.6	0.7	0.7	0.1	0.1
Amortization of deferred loan costs	0.2	0.1	—	—	—
Total fixed charges	$ 27.0	$ 12.6	$ 1.5	$ 0.1	$ 0.1
Ratio of earnings to fixed charges	0.4	5.6	49.7	437.0	190.0

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income (loss) from continuing operations before income or loss from equity method investments, plus fixed charges, plus distributed income of equity method investments, less capitalized interest. Fixed charges consist of interest expensed, capitalized interest, amortization of deferred loan costs, and an estimate of the interest within rental expense.

Exhibit 21.1

SUBSIDIARIES OF DCP MIDSTREAM PARTNERS, LP

Entity	Jurisdiction of Organization
Associated Louisiana Intrastate Pipe Line, LLC	Delaware
DCP Assets Holding GP, LLC	Delaware
DCP Assets Holding, LP	Delaware
DCP Black Lake Holding, LP	Delaware
DCP Collbran, LLC	Colorado
DCP Douglas, LLC	Colorado
DCP Intrastate Pipeline, LLC	Delaware
DCP Lindsay, LLC	Delaware
DCP Midstream Operating, LLC	Delaware
DCP Midstream Operating, LP	Delaware
DCP Midstream Partners Finance Corp.	Delaware
DCP Partners MEG Holdings, LLC	Colorado
Gas Supply Resources LLC	Texas
GSRI Transportation LLC	Texas
Pelico Pipeline, LLC	Delaware
Wilbreeze Pipeline, LP	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and in Amendment No. 1 to Registration Statements No. 333-142278 and No. 333-146832 on Form S-3 of our reports dated March 7, 2008, relating to (1) the consolidated financial statements and financial statement schedule of DCP Midstream Partners, LP (which report expresses an unqualified opinion and includes explanatory paragraphs referring to the preparation of the portion of the DCP Midstream Partners, LP consolidated financial statements attributable to (a) operations prior to December 7, 2005 (b) the wholesale propane logistics business and (c) DCP East Texas Holdings, LLC (formerly the East Texas Midstream Business), Discovery Producer Services, LLC, and a non-trading derivative instrument from the separate records maintained by DCP Midstream, LLC) and (2) the effectiveness of DCP Midstream Partners, LP's internal control over financial reporting appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-142271) and Form S-3 (No. 333-142278 and 333-146832) of DCP Midstream Partners, LP of our report dated February 25, 2008, with respect to the consolidated financial statements of Discovery Producer Services LLC, included in this Annual Report (Form 10-K) for the year ended December 31, 2007, filed with the Securities and Exchange Commission.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 6, 2008

Exhibit 23.3

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and in Amendment No. 1 to Registration Statements No. 333-142278 and No. 333-146832 on Form S-3 of our report dated March 7, 2008, relating to the consolidated financial statements and financial statement schedule of DCP East Texas Holdings, LLC (formerly the East Texas Midstream Business) as of December 31, 2007 and 2006 and for the three years in the period ending December 31, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the financial statements of DCP East Texas Holdings, LLC from the separate records maintained by DCP Midstream, LLC) appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

Exhibit 23.4

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and in Amendment No. 1 to Registration Statements No. 333-142278 and No. 333-146832 on Form S-3 of our report dated March 7, 2008, relating to the consolidated balance sheet of DCP Midstream GP, LP as of December 31, 2007 appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

Exhibit 23.5

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-142271 on Form S-8 and in Amendment No. 1 to Registration Statements No. 333-142278 and No. 333-146832 on Form S-3 of our report dated March 7, 2008, relating to the consolidated balance sheet of DCP Midstream, LLC as of December 31, 2007 appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Mark A. Borer certify that:

1. I have reviewed this annual report on Form 10-K of DCP Midstream Partners, LP for the fiscal year ended December 31, 2007;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 7, 2008

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
DCP Midstream GP, LLC

Exhibit 31.2

**Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002**

I, Thomas E. Long certify that:

1. I have reviewed this annual report on Form 10-K of DCP Midstream Partners, LP for the fiscal year ended December 31, 2007;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financials statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 7, 2008

/s/ Thomas E. Long
Thomas E. Long
Chief Financial Officer
DCP Midstream GP, LLC

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the Chief Executive Officer of DCP Midstream GP, LLC., a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the "Partnership"), hereby certifies that, to his knowledge on the date hereof:

(a) the annual report on Form 10-K of the Partnership for the fiscal year ended December 31, 2007, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Mark A. Borer

Mark A. Borer
Chief Executive Officer
March 7, 2008

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the Chief Financial Officer of DCP Midstream GP, LLC., a Delaware limited liability company and general partner of DCP Midstream GP, LP, general partner of DCP Midstream Partners, LP (the "Partnership"), hereby certifies that, to his knowledge on the date hereof:

(a) the annual report on Form 10-K of the Partnership for the fiscal year ended December 31, 2007, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Thomas E. Long

Thomas E. Long
Chief Financial Officer
March 7, 2008

Exhibit 99.1

DCP Midstream GP, LP
(A Delaware Limited Partnership)

Consolidated Balance Sheet
As of December 31, 2007

CONSOLIDATED BALANCE SHEET OF
DCP MIDSTREAM GP, LP

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
DCP Midstream GP, LLC
Denver, Colorado:

We have audited the accompanying consolidated balance sheet of DCP Midstream GP, LP (a wholly owned subsidiary of DCP Midstream, LLC) and subsidiaries (the "Company") as of December 31, 2007. This financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this financial statement based on our audit. The consolidated balance sheet gives retroactive effect to the acquisition of a 25% limited liability interest in DCP East Texas Holdings, LLC, a 40% limited liability interest in Discovery Producer Services LLC ("Discovery") and a nontrading derivative instrument from DCP Midstream, LLC by the Company on July 1, 2007, which has been accounted for in a manner similar to a pooling of interests as described in Note 4 to the consolidated balance sheet. We did not audit the financial statements of Discovery, an investment of the Company which is accounted for by the use of the equity method. The Company's equity in Discovery's net assets of $161,520,000 at December 31, 2007 is included in the accompanying consolidated balance sheet. Discovery's financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to amounts included for Discovery, is based solely on the report of such other auditors.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

In our opinion, such balance sheet presents fairly, in all material respects, the financial position of the Company as of December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

DCP MIDSTREAM GP, LP
CONSOLIDATED BALANCE SHEET

	December 31, 2007 (Millions)
ASSETS	
Current assets:	
Cash and cash equivalents	$ 24.5
Short-term investments	1.3
Accounts receivable:	
Trade, net of allowance for doubtful accounts of $1.2 million	81.7
Affiliates	52.1
Inventories	37.3
Unrealized gains on derivative instruments	3.1
Other	18.5
Total current assets	218.5
Restricted investments	100.5
Property, plant and equipment, net	500.7
Goodwill	80.2
Intangible assets, net	29.7
Equity method investments	187.2
Unrealized gains on derivative instruments	2.7
Other long-term assets	1.2
Total assets	$ 1,120.7
LIABILITIES AND PARTNERS' DEFICIT	
Current liabilities:	
Accounts payable:	
Trade	$ 110.2
Affiliates	55.6
Unrealized losses on derivative instruments	30.9
Accrued interest payable	1.6
Other	21.3
Total current liabilities	219.6
Long-term debt	630.0
Unrealized losses on derivative instruments	70.0
Other long-term liabilities	9.4
Total liabilities	929.0
Non-controlling interests	197.3
Commitments and contingent liabilities	
Partners' deficit:	
Partners' equity	177.6
Note receivable from DCP Midstream, LLC	(183.0)
Accumulated other comprehensive loss	(0.2)
Total partners' deficit	(5.6)
Total liabilities and partners' deficit	$ 1,120.7

See accompanying notes to consolidated balance sheet.

DCP MIDSTREAM GP, LP
NOTES TO CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2007

1. Description of Business and Basis of Presentation

DCP Midstream GP, LP, with its consolidated subsidiaries, or us, we or our, is a Delaware limited partnership, whose interests are owned by DCP Midstream, LLC and DCP Midstream GP, LLC. We own a 1.5% interest in and act as the general partner for DCP Midstream Partners, LP, or DCP Partners or the partnership, a master limited partnership formed in August 2005, which is engaged in the business of gathering, compressing, treating, processing, transporting and selling natural gas, producing, transporting, storing and selling propane and transporting and selling natural gas liquids, or NGLs, and condensate. DCP Partners' operations and activities are managed by us. We, in turn, are managed by our general partner, DCP Midstream GP, LLC, which we refer to as our General Partner, which is wholly-owned by DCP Midstream, LLC. DCP Midstream, LLC directs DCP Partners' business operations through their ownership and control of our General Partner. DCP Midstream, LLC and its affiliates' employees provide administrative support to DCP Partners and operate our assets. DCP Midstream, LLC is owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips.

The partnership includes: our Northern Louisiana system; our Southern Oklahoma system (acquired in May 2007); our limited liability company interests in DCP East Texas Holdings, LLC, or East Texas, and Discovery Producer Services LLC, or Discovery (acquired in July 2007); our Wyoming system and a 70% interest in our Colorado system (each acquired in August 2007); our wholesale propane logistics business (acquired in November 2006); and our NGL transportation pipelines.

The consolidated balance sheet has been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The consolidated balance sheet includes the accounts of DCP Midstream GP, LP and DCP Partners. We consolidate DCP Partners as we act as the general partner and as the limited partners do not have substantive kick-out or participating rights. DCP Partners' investments in greater than 20% owned affiliates, which are not variable interest rights and where DCP Partners does not exercise control, are accounted for using the equity method. All significant intercompany balances and transactions have been eliminated. Transactions between us and other DCP Midstream, LLC operations and other affiliates have been identified in the consolidated balance sheet as transactions between affiliates.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheet and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents — We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less to be cash equivalents.

Short-Term and Restricted Investments — We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments are used as collateral to secure the term loan portion of our credit facility and to finance gathering and compression asset acquisitions.

We have classified all short-term and restricted investments as available-for-sale as we do not intend to hold them to maturity, nor are they bought or sold with the objective of generating profit on short-term differences in prices. These investments are recorded at fair value, with changes in fair value recorded as unrealized gains and losses in accumulated other comprehensive (loss) income, or AOCI. The cost, including accrued interest on investments, approximates fair value, due to the short-term, highly liquid nature of the securities held by us, and as interest rates are re-set on a daily, weekly or monthly basis.

Inventories — Inventories, which consist primarily of propane, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Gas and NGL Imbalance Accounting — Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheet as accounts receivable—trade and accounts receivable—affiliates were imbalances of $1.6 million at December 31, 2007. Included in the consolidated balance sheet as accounts payable—trade were imbalances of $1.1 million at December 31, 2007.

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate, and increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability of a conditional asset retirement obligation as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Goodwill and Intangible Assets — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

Intangible assets consist primarily of commodity purchase contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit, ranging from approximately two to 25 years.

Long-Lived Assets — We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models.

Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Equity Method Investments — We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our equity method investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Unamortized Debt Expense — Expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. These expenses are recorded on the consolidated balance sheet as other long-term assets.

Accounting for Sales of Units by a Subsidiary — We account for sales of units by a subsidiary by recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. As a result, we have deferred approximately $3.6 million of gain on sale of common units in DCP Partners, which is included in other long-term liabilities in the consolidated balance sheet. This gain is related to DCP Partners' private placement in June 2007 and August 2007. We will recognize this gain in earnings upon conversion of all of DCP Partners' subordinated units to common units.

Accounting for Risk Management Activities and Financial Instruments — Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow protection activities. We are using the mark-to-market method of accounting for all commodity derivative instruments beginning in July 2007. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheet at its fair value as unrealized gains or unrealized losses on derivative instruments. Derivative assets and liabilities remain classified in our consolidated balance sheet as unrealized gains or unrealized losses on derivative instruments at fair value until the contractual settlement period impacts earnings.

Prior to July 1, 2007, we designated each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives were further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales, while certain non-trading derivatives, which are related to asset-based activities, are designated as non-trading derivative activity. For the periods presented, we did not have any trading derivative activity, however, we did have cash flow and fair value hedge activity, normal purchases and normal sales activity, and non-trading derivative activity included in the consolidated balance sheet.

Cash Flow and Fair Value Hedges — For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess, both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheet as unrealized gains or unrealized losses on derivative instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in partners' equity as AOCI. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to earnings in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheet at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in earnings.

Valuation — When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of December 31, 2007, included in the consolidated balance sheet as other current liabilities amounted to $0.7 million and as other long-term liabilities amounted to $1.0 million.

Equity-Based Compensation — Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Income Taxes — We are structured as a limited partnership which is a pass-through entity for federal income tax purposes.

3. Recent Accounting Pronouncements

Statement of Financial Accounting Standards, or SFAS, No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51," **or SFAS 160** — In December 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated financial position.

SFAS No. 141(R) "Business Combinations (revised 2007)," or SFAS 141(R) — In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115, or SFAS 159 — In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. The provisions of SFAS 159 were effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected on our consolidated financial position.

***SFAS No. 157, Fair Value Measurements*, or SFAS 157** — In September 2006, the FASB issued SFAS 157, which provides guidance for using fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we estimate a cumulative effect transition adjustment of an after-tax increase to partners' equity of approximately $7.3 million. This transition adjustment will directly affect the beginning balance of partners' equity.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While, we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

***FASB Interpretation Number, or FIN, No. 48, Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement 109,* or FIN 48** — In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a significant impact on our consolidated financial position.

4. Acquisitions

Gathering and Compression Assets

In August 2007, we acquired certain subsidiaries of Momentum Energy Group, Inc., or MEG, from DCP Midstream, LLC for approximately $165.8 million. As a result of the acquisition, we expanded our operations into the Piceance and Powder River producing basins, thus diversifying our business into new operating areas. The consideration consisted of approximately $153.8 million of cash and the issuance of 275,735 DCP Partners' common units to an affiliate of DCP Midstream, LLC that were valued at approximately $12.0 million. We have incurred post-closing purchase price adjustments to date that include a liability of $9.0 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of revolver and term loan borrowings under our amended credit agreement, along with the issuance of DCP Partners' common units through a private placement with certain institutional investors and cash on hand. In August 2007, we issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate. The proceeds from this private placement were used to purchase high-grade securities to fully secure our term loan borrowings. These units were registered with the Securities and Exchange Commission, or SEC, in January 2008.

The transfer of the MEG subsidiaries between DCP Midstream, LLC and us represents a transfer between entities under common control. Transfers between entities under common control are accounted for at DCP Midstream, LLC's carrying value, similar to the pooling method. DCP Midstream, LLC recorded its acquisition of the MEG subsidiaries under the purchase method of accounting, whereby the assets and liabilities were recorded at their respective fair values as of the date of the acquisition, including goodwill of approximately $50.9 million. The goodwill amount recognized relates primarily to projected growth in the Piceance basin due to significant natural gas reserves and high levels of drilling activity. We expect all of the goodwill to be tax deductible. DCP Midstream, LLC obtained third-party valuations for property, plant and equipment, and intangible assets. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained. When finalized, material adjustments to goodwill may result. The purchase price allocation is as follows:

		(Millions)
Cash consideration	$	153.8
Payable to DCP Midstream, LLC		9.0
Common limited partner units		12.0
Aggregate consideration	$	174.8

The purchase price allocation is as follows:		
Cash	$	11.8
Accounts receivable		14.1
Other assets		1.5
Property, plant and equipment		123.5
Goodwill		50.9
Intangible assets		15.5
Accounts payable		(11.1)
Other liabilities		(8.6)
Non-controlling interest in joint venture		(22.8)
Total purchase price allocation	$	174.8

On July 1, 2007, we acquired a 25% limited liability company interest in East Texas, a 40% limited liability company interest in Discovery and the Swap from DCP Midstream, LLC, in a transaction among entities under common control, for aggregate consideration of approximately $271.3 million, consisting of approximately $243.7 million in cash, including net working capital of $1.3 million and other adjustments, the issuance of 620,404 DCP Partners' common units to DCP Midstream, LLC valued at $27.0 million and the issuance of 12,661 general partner equivalent units valued at $0.6 million. We financed the cash portion of this transaction with borrowings of $245.9 million under our amended credit facility. The $118.0 million excess purchase price over the historical basis of the net acquired assets was recorded as a reduction to partners' equity, and the $27.6 million of common and general partner equivalent units issued as partial consideration for this transaction was recorded as an increase to partners' equity. The transfer of assets between DCP Midstream, LLC and us represents a transfer of assets between entities under common control. Transfers of net assets or exchanges of shares between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method.

In May 2007, we acquired certain gathering and compression assets located in southern Oklahoma, or the Southern Oklahoma system, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181.1 million.

In April 2007, we acquired certain gathering and compression assets located in northern Louisiana from Laser Gathering Company, LP for approximately $10.2 million.

5. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Omnibus Agreement

We have entered into an omnibus agreement, as amended, or the Omnibus Agreement, with DCP Midstream, LLC. Under the Omnibus Agreement, we are required to reimburse DCP Midstream, LLC for salaries of operating personnel and employee benefits as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. We also pay DCP Midstream, LLC an annual fee for centralized corporate functions performed by DCP Midstream, LLC on our behalf, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering.

All fees under the Omnibus Agreement are subject to adjustment annually for changes in the Consumer Price Index.

The Omnibus Agreement also addresses the following matters:

- DCP Midstream, LLC's obligation to indemnify us for certain liabilities and our obligation to indemnify DCP Midstream, LLC for certain liabilities;
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to derivative financial instruments, such as commodity price hedging contracts, to the extent that such credit support arrangements were in effect as of the closing of our initial public offering in December 2005, until the earlier to occur of the fifth anniversary of the closing of our initial public offering or such time as we obtain an investment grade credit rating from either Moody's Investor Services, Inc. or Standard & Poor's Ratings Group with respect to any of our unsecured indebtedness; and
- DCP Midstream, LLC's obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at the closing of our initial public offering until the expiration of such contracts.

Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if the general partner is removed without cause and units held by the general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a change of control of us, the general partner (DCP Midstream GP, LP) or the General Partner (DCP Midstream GP, LLC).

Following is a summary of the fees we incurred in 2007 under the Omnibus Agreement and the effective date for these fees, as well as other fees paid to DCP Midstream, LLC:

Terms	Effective Date	Year Ended December 31, 2007	2006	2005
			(Millions)	
Annual fee	2006	$ 5.0	$ 4.8	$ 0.3
Wholesale propane logistics business	November 2006	2.0	0.3	—
Southern Oklahoma	May 2007	0.1	—	—
Discovery	July 2007	0.1	—	—
Additional services	August 2007	0.2	—	—
MEG	August 2007	0.5	—	—
Total Omnibus Agreement		7.9	5.1	0.3
Other fees		2.1	3.0	8.8
Total		$ 10.0	$ 8.1	$ 9.1

Competition

None of DCP Midstream, LLC, nor any of its affiliates, including Spectra Energy and ConocoPhillips, is restricted, under either the partnership agreement or the Omnibus Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Spectra Energy and ConocoPhillips, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, DCP Midstream, LLC will indemnify us until December 7, 2008 against certain potential environmental claims, losses and expenses associated with the operation of the assets and occurring before the closing date of our initial public offering. DCP Midstream, LLC's maximum liability for this indemnification obligation does not exceed $15.0 million and DCP Midstream, LLC does not have any obligation under this indemnification until our aggregate losses exceed $250,000. DCP Midstream, LLC has no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after the closing date of our initial public offering. We have agreed to indemnify DCP Midstream, LLC against environmental liabilities related to our assets to the extent DCP Midstream, LLC is not required to indemnify us.

Additionally, DCP Midstream, LLC will indemnify us for losses attributable to title defects, retained assets and liabilities (including pre-closing litigation relating to contributed assets) and income taxes attributable to pre-closing operations. We will indemnify DCP Midstream, LLC for all losses attributable to the post-closing operations of the assets contributed to us, to the extent not subject to DCP Midstream, LLC's indemnification obligations. In addition, DCP Midstream, LLC has agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions required to be made by us to Black Lake Pipe Line Company, or Black Lake, associated with any repairs to the Black Lake pipeline that are determined to be necessary as a result of the currently ongoing pipeline integrity testing occurring from 2005 through June 2008. DCP Midstream, LLC has also agreed to indemnify us for up to $4.0 million of the costs associated with any repairs to the Seabreeze pipeline that were determined to be necessary as a result of pipeline integrity testing that occurred in 2006. Pipeline integrity testing and repairs are our responsibility and are recognized as operating and maintenance expense. Reimbursements of these expenses from DCP Midstream, LLC were not significant and were recognized by us as capital contributions.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC will indemnify us until October 31, 2008 for any breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, DCP Midstream, LLC agreed to indemnify us until October 31, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing, agreed to indemnify us until October 31, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing, agreed to indemnify us until October 31, 2010 if certain contractual matters result in a claim, and agreed to indemnify us indefinitely for breaches of the agreement. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $680,000 and is subject to a maximum liability of $6.8 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisitions of East Texas and Discovery from DCP Midstream, LLC, DCP Midstream, LLC will indemnify us until July 1, 2008 for the breach of the representations and warranties made under the acquisition agreement (except certain corporate related matters that survive indefinitely) and certain litigation, environmental matters, title defects and tax matters associated with these assets that were identified at the time of closing and that were attributable to periods prior to the closing date. In addition, the same affiliate of DCP Midstream, LLC agreed to indemnify us until July 1, 2008 for the overpayment or underpayment of trade payables or receivables that pertain to periods prior to closing and agreed to indemnify us until July 1, 2009 for any claims for fines or penalties of any governmental authority for periods prior to the closing and that are associated with certain East Texas assets that were formerly owned by Gulf South and UP Fuels, and agreed to indemnify us indefinitely for breaches of the agreement and certain existing claims. The indemnity obligation for breach of the representations and warranties is not effective until claims exceed in the aggregate $2.7 million and is subject to a maximum liability of $27.0 million. This indemnity obligation for all other claims other than a breach of the representations and warranties does not become effective until an individual claim or series of related claims exceed $50,000.

In connection with our acquisition of certain subsidiaries of MEG, DCP Midstream will indemnify us following the closing on August 29, 2007 for any breach of the representations and warranties made under the acquisition agreement and certain other matters associated with these assets. DCP Midstream agreed to indemnify us until August 29, 2008 for any breach of the representations and warranties (except certain corporate related matters that survive indefinitely), and indefinitely for breaches of the agreement.

Other Agreements and Transactions with DCP Midstream, LLC

DCP Midstream, LLC owns certain assets and is party to certain contractual relationships around our Pelico system that are periodically used for the benefit of Pelico. DCP Midstream, LLC is able to source natural gas upstream of Pelico and deliver it to the inlet of the Pelico system, and is able to take natural gas from the outlet of the Pelico system and market it downstream of Pelico. Because of DCP Midstream, LLC's ability to move natural gas around Pelico, there are certain contractual relationships around Pelico that define how natural gas is bought and sold between us and DCP Midstream, LLC. The agreement is described below:

- DCP Midstream, LLC will supply Pelico's system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred.
- If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index-based price, less a contractually agreed-to marketing fee.
- In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC, plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential, plus a fixed fuel charge and other related adjustments.

In addition, we sell NGLs and condensate from our Minden and Ada processing plants, and condensate from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation and other charges from the tailgate of the respective asset. We also sell propane to a subsidiary of DCP Midstream, LLC.

We also have a contractual arrangement with a subsidiary of DCP Midstream, LLC that provides that DCP Midstream, LLC will pay us to transport NGLs over our Seabreeze pipeline, pursuant to a fee-based rate that will be applied to the volumes transported. DCP Midstream, LLC is the sole shipper on the Seabreeze pipeline under a transportation agreement.

In December 2006, we completed construction of our Wilbreeze pipeline, which connects a DCP Midstream, LLC gas processing plant to our Seabreeze pipeline. The project is supported by an NGL product dedication agreement with DCP Midstream, LLC.

We anticipate continuing to purchase commodities from and sell commodities to DCP Midstream, LLC in the ordinary course of business.

In the second quarter of 2006, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for capital projects, which were forecasted to be completed prior to DCP Partners' initial public offering, but were not completed by that date. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $ $0.3 million during 2007 to reimburse us for the capital costs we incurred, primarily for growth capital projects.

In conjunction with our acquisition of a 40% limited liability company interest in Discovery from DCP Midstream, LLC in July 2007, we entered into a letter agreement with DCP Midstream, LLC whereby DCP Midstream, LLC will make capital contributions to us as reimbursement for certain Discovery capital projects, which were forecasted to be completed prior to our acquisition of a 40% limited liability company interest in Discovery. Pursuant to the letter agreement, DCP Midstream, LLC made capital contributions to us of $0.3 million during 2007, to reimburse us for these capital projects. As of December 31, 2007, $0.1 million of the capital contributions are included in accounts receivable — affiliates in the consolidated balance sheet.

We have a note receivable from DCP Midstream, LLC totaling $183.0 million. This note is due on demand; however, we do not anticipate requiring DCP Midstream, LLC to repay this amount. Accordingly we have reflected this receivable as a component of partners' deficit. The note receivable bears interest at the greater of 5.00% or the applicable federal rate in effect under section 1274(d) of the Internal Revenue Code of 1986. The interest rate in effect on the note was 5.00% at December 31, 2007. All interest income earned under the note has been distributed to DCP Midstream, LLC.

In accordance with our partnership agreement, we distribute all available cash to our partners according to their respective ownership interest.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percentage-of-proceeds gathering and processing arrangements, gas purchase and gas sales agreements. We anticipate continuing to purchase from and sell these commodities to ConocoPhillips and its affiliates in the ordinary course of business. In addition, we may be reimbursed by ConocoPhillips for certain capital projects where the work is performed by us. We received $2.9 million of capital reimbursements during the year ended December 31, 2007.

We had accounts receivable and accounts payable with affiliates as follows:

	December 31, 2007 (Millions)
DCP Midstream, LLC:	
Accounts receivable	$47.3
Accounts payable	$53.3
Spectra Energy:	
Accounts receivable	$ 1.5
ConocoPhillips:	
Accounts receivable	$ 3.3
Accounts payable	$ 2.3

The following summarizes the unrealized losses on derivative instruments with affiliates:

	December 31, 2007 (Millions)
DCP Midstream, LLC:	
Unrealized losses—current	$(2.7)

6. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2007 (Millions)
Gathering systems	15 — 30 Years	$ 371.3
Processing plants	25 — 30 Years	91.4
Terminals	25 — 30 Years	24.2
Transportation	25 — 30 Years	141.0
General plant	3 — 5 Years	4.0
Construction work in progress		25.5
Property, plant and equipment		657.4
Accumulated depreciation		(156.7)
Property, plant and equipment, net		$ 500.7

The above amounts include accrued capital expenditures of $8.4 million as of December 31, 2007, which are included in other current liabilities in the consolidated balance sheet.

Asset Retirement Obligations — Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The asset retirement obligation, included in other long-term liabilities in the consolidated balance sheet, was $3.1 million at December 31, 2007.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

7. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31, 2007 (Millions)
Beginning of period	$ 29.3
Acquisitions	50.9
End of period	$ 80.2

Goodwill of $29.3 million represents the amount that was recognized by DCP Midstream, LLC when it acquired certain assets which are now included in our Wholesale Propane Logistics segment, and was allocated based on fair value to the wholesale propane logistics business in order to present historical information about the assets we acquired in November 2006. The increase in goodwill during 2007 of $50.9 million represents the amount that we recognized in connection with our acquisition of the MEG subsidiaries from DCP Midstream, LLC.

We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment tests indicated that our reporting unit's fair value exceeded its carrying or book value; therefore, we did not record any impairment charges during the year ended December 31, 2007.

Intangible assets consist primarily of commodity purchase contracts and relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheet as intangible assets, net, and are as follows:

	December 31, 2007 (Millions)
Gross carrying amount	$ 32.4
Accumulated amortization	(2.7)
Intangible assets, net	$ 29.7

Intangible assets increased as a result of the Southern Oklahoma and MEG acquisitions, through which $12.5 million and $15.5 million, respectively, of intangible assets were acquired.

As of December 31, 2007, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 20 years.

8. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of December 31, 2007	Carrying Value as of December 31, 2007 (Millions)
Discovery Producer Services LLC	40%	$ 117.9
DCP East Texas Holdings, LLC	25%	62.9
Black Lake Pipe Line Company	45%	6.2
Other	50%	0.2
Total equity method investments		$ 187.2

Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana, a natural gas pipeline from offshore deep water in the Gulf of Mexico that transports gas to its processing plant in Larose, Louisiana with a design capacity of 600 MMcf/d and approximately 280 miles of pipe, and several laterals in the Gulf of Mexico. There was a deficit between the carrying amount of the investment and the underlying equity of Discovery of $43.7 million at December 31, 2007, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Discovery.

East Texas is engaged in the business of gathering, transporting, treating, compressing, processing, and fractionating natural gas and NGLs. Its operations, located near Carthage, Texas, include a natural gas processing complex with a total capacity of 780 MMcf/d and a natural gas liquids fractionator. The facility is connected to an approximately 845-mile gathering system, as well as third party gathering systems. The complex includes and is adjacent to the Carthage Hub, which delivers residue gas to interstate and intrastate pipelines. The Carthage Hub, with an aggregate delivery capacity of 1.5 Bcf/d, acts as a key exchange point for the purchase and sale of residue gas.

Black Lake owns a 317-mile NGL pipeline, with a throughput capacity of approximately 40 MBbls/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. There was a deficit between the carrying amount of the investment and the underlying equity of Black Lake of $6.4 million at December 31, 2007, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

The following summarizes financial information of our equity method investments:

	December 31, 2007 (Millions)
Balance sheet:	
Current assets	$ 168.8
Long-term assets	630.3
Current liabilities	100.9
Long-term liabilities	14.9
Net assets	$ 683.3

9. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts. The following summarizes the estimated fair value of financial instruments:

	December 31, 2007	
	Carrying Amount	Estimated Fair Value
	(Millions)	
Restricted investments	$100.5	$100.5
Accounts receivable	$133.8	$133.8
Accounts payable	$165.8	$165.8
Net unrealized losses on derivative instruments	$ (95.1)	$ (95.1)
Long-term debt	$630.0	$630.0

The fair value of restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value.

The carrying value of long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

10. Debt

Long-term debt was as follows:

	Principal Amount at December 31, 2007 (Millions)
Revolving credit facility, weighed-average interest rate of 5.47%, due June 21, 2012	$ 530.0
Term loan facility, interest rate of 5.05%, due June 21, 2012	100.0
Total long-term debt	$ 630.0

Credit Agreements

On June 21, 2007, we entered into the Amended and Restated Credit Agreement, or the Amended Credit Agreement, that replaced our existing credit agreement, or the Credit Agreement, which consists of:

- a $600.0 million revolving credit facility; and
- a $250.0 million term loan facility.

At December 31, 2007, we had $0.2 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2007. We have incurred $0.6 million of debt issuance costs associated with the Amended Credit Agreement. These expenses are deferred as other long-term assets in the consolidated balance sheet and will be amortized over the term of the Amended Credit Agreement.

Under the Amended Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank's prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon our leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on our applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to either: (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank's prime rate or the Federal Funds rate plus 0.50%.

The Amended Credit Agreement requires us to maintain a leverage ratio (the ratio of our consolidated indebtedness to our consolidated EBITDA, in each case as is defined by the Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. The Amended Credit Agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, in each case as is defined by the Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loan

In May 2007, we entered into a two-month bridge loan, or the Bridge Loan, which provided for borrowings up to $100.0 million, and had terms and conditions substantially similar to those of our Credit Agreement. In conjunction with our entering into the Bridge Loan, our Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100.0 million, which was due and payable no later than August 9, 2007.

We used borrowings on the Bridge Loan of $88.0 million to partially fund the Southern Oklahoma acquisition. The remaining $12.0 million available for borrowing on the Bridge Loan was not utilized. We used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88.0 million outstanding on the Bridge Loan in June 2007.

11. Non-Controlling Interest

Non-controlling interest represents (1) the ownership interests of DCP Partners' public unitholders in net assets of DCP Partners through DCP Partners' publicly traded common units; (2) affiliate ownership interests in common units and in all of the subordinated units; and (3) the non-controlling interest holders' portion of the net assets of our Collbran Valley Gas Gathering system joint venture, acquired with the MEG acquisition in August 2007.

We own a 1.5% general partner interest in DCP Partners. For financial reporting purposes, the assets and liabilities of DCP Partners are consolidated with those of our own, with any third party and affiliate investors' interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party and affiliate investors.

At December 31, 2007, DCP Partners had outstanding 16,840,326 common units and 7,142,857 subordinated units.

General — DCP Partners' partnership agreement requires that, within 45 days after the end of each quarter, DCP Partners distribute all Available Cash (defined below) to unitholders of record on the applicable record date, as determined by us as the general partner.

In November 2007, DCP Partners' universal shelf registration statement on Form S-3 was declared effective by the SEC. The universal shelf registration statement has a maximum aggregate offering price of $1.5 billion, which will allow DCP Partners to register and issue additional partnership units and debt obligations.

In June 2007, DCP Partners entered into a private placement agreement with a group of institutional investors for $130.0 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $128.5 million, net of offering costs.

In July 2007, DCP Partners issued 620,404 common units to DCP Midstream, LLC as partial consideration for the purchase of Discovery, East Texas and the Swap. In August 2007, DCP Partners issued 275,735 common units to DCP Midstream, LLC as partial consideration for the purchase of certain subsidiaries of MEG.

In August 2007, DCP Partners issued 2,380,952 common units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100.0 million in the aggregate.

In January 2008, DCP Partners' registration statement on Form S-3 to register the 3,005,780 common limited partner units represented in the June 2007 private placement agreement and the 2,380,952 common limited partner units represented in the August 2007 private placement agreement was declared effective by the SEC.

Definition of Available Cash — Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by us as the general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to the unitholders and to us as the general partner for any one or more of the next four quarters;
- plus, if we, as the general partner so determine, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

General Partner Interest and Incentive Distribution Rights — Prior to June 2007, as the general partner, we were entitled to 2% of all quarterly distributions that we make prior to DCP Partners' liquidation. We have the right, but not the obligation, to contribute a proportionate amount of capital to maintain our current general partner interest. We did not participate in certain issuances of common units by DCP Partners during 2007. Therefore, our 2% interest in these distributions was reduced to 1.5%.

The incentive distribution rights held by us as the general partner entitle us to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Our incentive distribution rights were not reduced as a result of these private placement agreements, and will not be reduced if DCP Partners issues additional units in the future and we do not contribute a proportionate amount of capital to DCP Partners to maintain our current general partner interest. Please read the *Distributions of Available Cash during the Subordination Period* and *Distributions of Available Cash after the Subordination Period* sections below for more details about the distribution targets and their impact on our incentive distribution rights.

Subordinated Units — All of the subordinated units are held by DCP Midstream, LLC. DCP Partners' partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the Minimum Quarterly Distribution, plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The subordination period has an early termination provision that permits 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2008 and the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in the partnership agreement are satisfied. DCP Partners determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2008 and, therefore, 50% of the subordinated units converted into common units. DCP Partners' board of directors and the conflicts committee of the board certified that all conditions for early conversion were satisfied. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period — DCP Partners' partnership agreement, after adjustment for our relative ownership level, currently 1.5%, requires that DCP Partners make distributions of Available Cash for any quarter during the subordination period in the following manner:

- *first*, to the common unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, to the common unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, to the subordinated unitholders and us as the general partner, in accordance with their pro rata interest, until DCP Partners distributes for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, to all unitholders and us as the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter (the First Target Distribution);
- *fifth*, 13% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter (the Second Target Distribution);
- *sixth*, 23% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 48% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period — DCP Partners' partnership agreement, after adjustment for our relative ownership level, requires that DCP Partners make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, to all unitholders and us as the general partner, in accordance with their pro rata interest, until each unitholder receives a total of $0.4025 per unit for that quarter;
- *second*, 13% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.4375 per unit for that quarter;
- *third*, 23% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders pro rata until each unitholder receives a total of $0.525 per unit for that quarter; and
- *thereafter*, 48% to us as the general partner, plus our pro rata interest, and the remainder to all unitholders.

The following table presents DCP Partners' cash distributions paid in 2007:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2007	$0.550	$14.7
August 14, 2007	0.530	12.4
May 15, 2007	0.465	8.6
February 14, 2007	0.430	7.8

12. Partners' Deficit

At December 31, 2007, partners' deficit consisted of our capital account, a note receivable from DCP Midstream, LLC and accumulated other comprehensive loss.

As of December 31, 2007, we had a deficit balance of $5.6 million in our partners' deficit account. This negative balance does not represent an asset to us and does not represent obligations by us to contribute cash or other property. The partners' deficit account generally consists of our cumulative share of net income less cash distributions made plus capital contributions made. Cash distributions that we receive during a period from DCP Partners may exceed our interest in DCP Partners' net income for the period. DCP Partners makes quarterly cash distributions of all of its Available Cash, defined above. Future cash distributions that exceed net income and contributions made will result in an increase in the deficit balance in the partners' deficit account.

13. Risk Management and Hedging Activities

The impact of our derivative activity on our financial position is summarized below:

	December 31, 2007 (Millions)
Interest rate cash flow hedges:	
Net deferred losses in AOCI	$(0.2)

For the year ended December 31, 2007, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate the effects of the identified risks. In general, we attempt to mitigate risks related to the variability of future cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. We have established a comprehensive risk management policy, or the Risk Management Policy, and a risk management committee, to monitor and manage market risks associated with commodity prices and interest rates. Our Risk Management Policy prohibits the use of derivative instruments for speculative purposes.

As of December 31, 2007, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $18.2 million, which is included in other current assets on the consolidated balance sheet.

Commodity Price Risk — Our operations of gathering, processing, and transporting natural gas, and the accompanying operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. To the extent that we carry propane inventories or our sales and supply arrangements are not aligned, we are exposed to market variables and commodity price risk. The amount and type of price risk is dependent on the mechanisms and locations for purchases, sales, transportation and storage of propane.

We manage our commodity derivative activities in accordance with our Risk Management Policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Interest Rate Risk — Interest rates on credit facility balances and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Credit Risk — In the Natural Gas Services segment, we sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. In the Wholesale Propane Logistics segment, we sell primarily to retail propane distributors. In the NGL Logistics segment, our principal customers include an affiliate of DCP Midstream, LLC, producers and marketing companies. Concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. We operate under DCP Midstream, LLC's corporate credit policy. DCP Midstream, LLC's corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with DCP Midstream, LLC's credit policy and guidelines. The agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Commodity Cash Flow Protection Activities — We used NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to earnings in the same accounts as the item being hedged. The impact of our derivative activity on our consolidated financial position as of December 31, 2007 is insignificant.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, an insignificant amount of the remaining net loss deferred in AOCI at December 31, 2007 is expected to be reclassified to sales of natural gas, propane, NGLs and condensate, through December 2011, as the hedged transactions impact earnings. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in earnings.

As of December 31, 2007, we have mitigated a portion of our expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with natural gas, NGLs and crude oil derivatives.

Other Asset-Based Activity —To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. We occasionally will enter into financial derivatives to lock in price variability across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Our wholesale propane logistics business is generally designed to establish stable margins by entering into supply arrangements that specify prices based on established floating price indices and by entering into sales agreements that provide for floating prices that are tied to our variable supply costs plus a margin. Occasionally, we may enter into fixed price sales agreements in the event that a retail propane distributor desires to purchase propane from us on a fixed price basis. We manage this risk with both physical and financial transactions, sometimes using non-trading derivative instruments, which generally allow us to swap our fixed price risk to market index prices that are matched to our market index supply costs. In addition, we may on occasion use financial derivatives to manage the value of our propane inventories. These financial derivatives are accounted for using mark-to-market accounting with changes in fair value recognized in current period earnings.

Commodity Fair Value Hedges — Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) to reduce our cash flow exposure to fixed price risk by swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index-based).

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated balance sheet is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Interest Rate Cash Flow Hedges — We mitigate a portion of our interest rate risk with interest rate swaps, which reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with an aggregate of $425.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheet. As a result, an insignificant amount of the remaining net loss deferred in AOCI at December 31, 2007 is expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

14. Equity-Based Compensation

On November 28, 2005, the board of directors of the General Partner adopted a long-term incentive plan, or LTIP, for employees, consultants and directors of the General Partner and its affiliates who perform services for us, effective as of December 7, 2005. Under the LTIP, equity-based instruments may be granted to our key employees. The LTIP provides for the grant of limited partner units, or

LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the LTIP. Awards that are canceled or forfeited, or are withheld to satisfy the General Partner’s tax withholding obligations, are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the General Partner’s board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to directors in conjunction with our initial public offering, which are subject to graded vesting provisions.

Awards granted to directors are accounted for as equity-based awards and all other awards are accounted for as liability awards.

Performance Units — We have awarded phantom LPUs, or Performance Units, pursuant to the LTIP to certain employees. Performance Units generally vest in their entirety at the end of a three year performance period. The number of Performance Units that will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance payout is determined by the compensation committee of the board of directors of the General Partner. The DERs will be paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2007, 28,350 units are expected to vest on December 31, 2008 and 27,150 units are expected to vest on December 31, 2009.

At December 31, 2007, there was approximately $1.4 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 1.5 years. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	23,090	$26.96	
Granted	29,610	$37.29	
Forfeited	(5,740)	$31.39	
Outstanding at December 31, 2007	46,960	$32.93	$45.95
Expected to vest (a)	55,500	$32.93	$45.95

(a) Based on our December 31, 2007 estimated achievement of specified performance targets, the number of performance units granted in 2006 that will ultimately vest is estimated at 143% of the targeted units granted.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in earnings.

Phantom Units — In conjunction with our initial public offering, in January 2006 the General Partner’s board of directors awarded phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of affiliates of the General Partner. Of the remaining Phantom Units outstanding at December 31, 2007, 2,001 units are expected to vest on January 3, 2008 and 17,698 units are expected to vest on January 3, 2009.

In 2007, we granted 4,500 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of the General Partner as part of their annual director fees for 2007. Of these Phantom Units, 4,000 units vested during 2007 and 500 units are expected to vest on February 7, 2008.

The DERs are paid quarterly in arrears.

At December 31, 2007, there was approximately $0.3 million of unrecognized compensation expense related to the Phantom Units that is expected to be recognized over a weighted-average period of 1.0 year. The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2006	24,700	$24.05	
Granted	4,500	$42.90	
Forfeited	(2,333)	$24.05	
Vested	(6,668)	$35.23	
Outstanding at December 31, 2007	20,199	$24.56	$45.95
Expected to vest	20,199	$24.56	$45.95

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in earnings.

We intend to settle the awards issued under the LTIP in cash upon vesting, with the exception of the units granted to directors. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of DCP Partners' common units at each measurement date. During the year ended December 31, 2007, 2,668 units vested and were settled in cash for $0.1 million, and 4,000 units were settled with the issuance of limited partner units.

15. Income Taxes

We are structured as a master limited partnership, which is a pass-through entity for federal income tax purposes. Accordingly, we had no deferred tax balances as of December 31, 2007.

In May 2006, the state of Texas enacted a margin-based franchise tax into law that replaced the existing franchise tax, commonly referred to as the Texas margin tax. The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. As a result of the change in Texas franchise law, our status in the state of Texas changed from non-taxable to taxable. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year. The deferred and current tax liabilities associated with the Texas margin tax were insignificant.

16. Commitments and Contingent Liabilities

Litigation

Driver — In August 2007, Driver Pipeline Company, Inc., or Driver, filed a lawsuit against us, in District Court, Jackson County, Texas. The litigation stems from an ongoing commercial dispute involving the construction of the Wilbreeze pipeline, which was completed in December 2006. Driver was the primary contractor for construction of the pipeline and the construction process was managed for us by DCP Midstream, LP. Driver claims damages in the amount of $2.4 million for breach of contract. We believe Driver's position in this litigation is without merit and we intend to vigorously defend ourselves against this claim. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated financial position.

El Paso — In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against us and DCP Assets Holding, LP, one of our affiliates, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which is prior to our ownership of this asset. El Paso claims damages, including interest, in the amount of $5.7 million in the litigation, the bulk of which stems from audit claims under our commercial contract for historical periods prior to our ownership of this asset. We will only be responsible for potential payments, if any, for claims that involve periods of time after the date we acquired this asset from DCP Midstream, LLC in December 2005. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated financial position.

Other — We are not a party to any other significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our consolidated financial position.

Insurance — We contract with a third party insurer for our primary general liability insurance covering third party exposures, and for our property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense. DCP Midstream, LLC provides our remaining insurance coverage through third party insurers for: (1) statutory workers' compensation insurance; (2) automobile liability insurance for all owned, non-owned and hired vehicles; (3) excess liability insurance above the established primary limits for general liability and automobile liability insurance; and (4) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated financial position.

Indemnification — DCP Midstream, LLC has indemnified us for certain potential environmental claims, losses and expenses associated with the operation of the assets of certain of our predecessor operations. See the "Indemnification" section of Note 5 for additional details.

Other Commitments and Contingencies — We utilize assets under operating leases in several areas of operation. Minimum rental payments under our various operating leases in the year indicated are as follows at December 31, 2007:

	(Millions)
2008	$ 9.7
2009	7.9
2010	7.1
2011	6.2
2012	5.8
Thereafter	7.0
Total minimum rental payments	$ 43.7

17. Business Segments

Our operations are located in the United States and are organized into three reporting segments: (1) Natural Gas Services; (2) Wholesale Propane Logistics; and (3) NGL Logistics.

Natural Gas Services — The Natural Gas Services segment consists of (1) the Northern Louisiana system; (2) the Southern Oklahoma system that was acquired in May 2007; (3) our 25% limited liability company interest in East Texas, our 40% limited liability company interest in Discovery, and the losses associated with the Swap acquired in July 2007; and (4) the assets of the MEG subsidiaries that were acquired in August 2007.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which is currently idle, one leased marine terminal, one pipeline terminal and access to several open access pipeline terminals.

NGL Logistics — The NGL Logistics segment consists of the Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated 45% equity interest in the Black Lake interstate NGL pipeline. DCP Midstream, LLC owns a 5% interest in Black Lake and an affiliate of BP PLC owns the remaining interest and is the operator of Black Lake. The Wilbreeze transportation pipeline began operations in December 2006.

These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Gross margin is a performance measure utilized by management to monitor the business of each segment.

The following table sets forth our segment information:

	December 31, 2007 (Millions)
Segment long-term assets:	
Natural Gas Services (a)	$ 710.7
Wholesale Propane Logistics	52.6
NGL Logistics	34.8
Other (b)	104.1
Total long-term assets	902.2
Current assets	218.5
Total assets	$ 1,120.7

(a) Long-term assets for our Natural Gas Services segment increased in 2007 as a result of our Southern Oklahoma acquisition in May 2007, and our acquisition of certain MEG subsidiaries in August 2007.

(b) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, and other long-term assets.

18. Subsequent Events

On January 24, 2008, the board of directors of the General Partner declared a quarterly distribution of $0.57 per unit, that was paid on February 14, 2008, to unitholders of record on February 7, 2008. This distribution of $0.57 per unit exceeds the highest target distribution level (see Note 11 for discussion of distributions of available cash).

In January 2008, we received a distribution from Discovery of $11.2 million for the fourth quarter of 2007, and we contributed $1.6 million to Discovery to fund our share of a capital expansion project.

Subsequent to December 31, 2007, we executed a series of derivative instruments to mitigate a portion of our anticipated commodity exposure. We entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and we entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.

In February 2008, DCP Partners satisfied the financial tests contained in its partnership agreement for the early conversion of 50% of the outstanding subordinated units held by DCP Midstream, LLC into common units. Prior to the conversion, DCP Midstream, LLC held 7,142,857 subordinated units, and after the conversion, DCP Midstream, LLC holds 3,571,429 subordinated units, which may convert into common units in the first quarter of 2009 if certain additional financial tests contained in DCP Partners' partnership agreement are satisfied.

In February 2008, one of our three primary propane suppliers terminated its supply contract with us. We are actively seeking alternative sources of supply and believe such supply sources are available on commercially acceptable terms.

As of March 3, 2008, we posted collateral with certain counterparties to our commodity derivative instruments of approximately $47.9 million. On March 4, 2008, we entered into a temporary agreement with a counterparty to certain of our swap contracts, whereby our collateral threshold was increased by $20.0 million, resulting in a corresponding reduction of our posted collateral.

In February 2008, we borrowed $35.0 million under our revolving credit facility, $10.0 million of which has since been repaid. In March 2008, we borrowed $30.0 million under our revolving credit facility and retired $30.0 million of outstanding indebtedness under our term loan facility. As a result, we liquidated $30.0 million of restricted investments securing the term loan portion of our credit facility, the proceeds of which were used for working capital purposes. As a result of the above activity, the borrowing capacity under our revolving credit facility was increased to $630.0 million. We had $585.0 million outstanding under our revolving credit facility as of March 6, 2008.

Exhibit 99.2

DCP Midstream, LLC
Consolidated Balance Sheet
As of December 31, 2007

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheet of DCP Midstream, LLC and subsidiaries (the "Company") as of December 31, 2007. This financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

In our opinion, such balance sheet presents fairly, in all material respects, the financial position of the Company as of December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

DCP MIDSTREAM, LLC
CONSOLIDATED BALANCE SHEET
As of December 31, 2007
(millions)

	2007
ASSETS	
Current assets:	
Cash and cash equivalents	$ 71
Short-term investments	9
Accounts receivable:	
Customers, net of allowance for doubtful accounts of $5 million	1,254
Affiliates	386
Other	48
Inventories	117
Unrealized gains on mark-to-market and hedging instruments	301
Other	62
Total current assets	2,248
Property, plant and equipment, net	4,443
Restricted investments	101
Investments in unconsolidated affiliates	204
Intangible assets, net	312
Goodwill	556
Unrealized gains on mark-to-market and hedging instruments	69
Deferred income taxes	7
Other non-current assets	38
Other non-current assets—affiliates	27
Total assets	$ 8,005
LIABILITIES AND MEMBERS' EQUITY	
Current liabilities:	
Accounts payable:	
Trade	$ 1,499
Affiliates	122
Other	54
Unrealized losses on mark-to-market and hedging instruments	347
Distributions payable to members	123
Accrued interest payable	56
Accrued taxes	55
Other	204
Total current liabilities	2,460
Deferred income taxes	16
Long-term debt	2,930
Unrealized losses on mark-to-market and hedging instruments	120
Other long-term liabilities	323
Non-controlling interests	193
Commitments and contingent liabilities	
Members' equity:	
Members' interest	1,974
Retained earnings	—
Accumulated other comprehensive loss	(11)
Total members' equity	1,963
Total liabilities and members' equity	$ 8,005

See Notes to Consolidated Balance Sheet.

DCP MIDSTREAM, LLC
NOTES TO CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2007

1. General and Summary of Significant Accounting Policies

Basis of Presentation — DCP Midstream, LLC, with its consolidated subsidiaries, us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of natural gas gathering, processing, compression, transportation and storage, and natural gas liquid, or NGL, fractionation, transportation, gathering, treating, processing and storage, as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

We formed DCP Midstream Partners, LP, a master limited partnership, or DCP Partners, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. DCP Partners completed their initial public offering in December 2005. As of December 31, 2007 we owned a 33.9% limited partnership interest and a 1.5% general partnership interest in DCP Partners, as well as incentive distribution rights that entitle us to receive an increasing share of available cash when pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. Since we exercise control over DCP Partners, we account for them as a consolidated subsidiary.

Prior to January 2, 2007, we were owned 50% by Duke Energy Corporation, or Duke Energy. On January 2, 2007, Duke Energy created two separate publicly traded companies by spinning off their natural gas businesses, including their 50% ownership interest in us, to Duke Energy shareholders. As a result of this transaction, Duke Energy's 50% ownership interest in us was transferred to a new company, Spectra Energy. This transaction is referred to in this report as "the Spectra spin." For periods prior to January 2, 2007, references to Spectra Energy are interchangeable with Duke Energy. Effective January 2, 2007, Spectra Energy refers to the newly formed public company.

We are governed by a five member board of directors, consisting of two voting members from each parent and our Chief Executive Officer and President, a non-voting member. All decisions requiring board of directors' approval are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

The consolidated balance sheet includes the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control, variable interest entities where we are the primary beneficiary, and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

Use of Estimates — Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could be different from these estimates.

Cash and Cash Equivalents — Cash and cash equivalents includes all cash balances and highly liquid investments with an original maturity of three months or less.

***Short-Term and Restricted Investments* —** We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted. We have classified all short-term and restricted debt investments as available-for-sale and they are carried at fair market value. Unrealized gains and losses on available-for-sale securities are recorded in the consolidated balance sheet as accumulated other comprehensive income (loss), or AOCI. No such gains or losses were deferred in AOCI at December 31, 2007. Restricted investments consist of collateral for DCP Partners' term loan. The costs, including accrued interest on investments, approximates fair value due to the short-term, highly liquid nature of the securities held by us and as interest rates are re-set on a daily, weekly or monthly basis.

Inventories — Inventories consist primarily of natural gas and NGLs held in storage for transportation and processing and sales commitments. Inventories are valued at the lower of weighted average cost or market. Transportation costs are included in inventory on the consolidated balance sheet.

Accounting for Risk Management and Derivative Activities and Financial Instruments — Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We are using the mark-to-market method of accounting for all commodity derivative instruments beginning in July 2007. As a result, the remaining net loss deferred in AOCI is being reclassified to sales of natural gas and petroleum products through December 2011, as the derivative transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheet at its fair value as unrealized gains or unrealized losses on mark-to-market and hedging instruments. Derivative assets and liabilities remain classified in the consolidated balance sheet as unrealized gains or unrealized losses on mark-to-market and hedging instruments at fair value until the contractual delivery period impacts earnings.

We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or a normal purchase or normal sale contract, while certain non-trading derivatives, which are related to asset based activity, are non-trading mark-to-market derivatives. For each of our derivatives, the accounting method and presentation in the consolidated statement of operations and comprehensive income are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method [b]	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge [a]	Hedge method [c]	Gross basis in the same consolidated statement of operations and comprehensive income category as the related hedged item
Fair Value Hedge	Hedge method [c]	Gross basis in the same consolidated statement of operations and comprehensive income category as the related hedged item
Normal Purchase or Normal Sale	Accrual method [d]	Gross basis upon settlement in the corresponding consolidated statement of operations and comprehensive income category based on purchase or sale
Non-Trading Derivatives	Mark-to-market method [b]	Net basis in trading and marketing gains and losses

a Effective July 1, 2007, all commodity cash flow hedges are classified as non-trading derivative activity. Our interest rate swaps continue to be accounted for as cash flow hedges.

b Mark-to-market—An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statement of operations and comprehensive income in trading and marketing gains and losses during the current period.

c Hedge method—An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheet as unrealized gains or unrealized losses on mark-to-market and hedging instruments. For cash flow hedges, there is no recognition in the consolidated statement of operations and comprehensive income for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statement of operations and comprehensive income in the same category as the related hedged item.

d Accrual method—An accounting method whereby there is no recognition in the consolidated balance sheet or consolidated statement of operations and comprehensive income for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges — For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheet as unrealized gains or unrealized losses on mark-to-market and hedging instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheet as AOCI and the ineffective portion is recorded in the consolidated statement of operations and comprehensive income. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statement of operations and comprehensive income in the same accounts as the item being hedged. We discontinue hedge accounting prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheet at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting changes in value of the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated statement of operations and comprehensive income.

Valuation — When available, quoted market prices or prices obtained through external sources are used to determine a contract’s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment — Property, plant and equipment are recorded at original cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability for conditional asset retirement obligations as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Investments in Unconsolidated Affiliates — We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such investments may have experienced an other than temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether any impairment has occurred. Management assesses the fair value of our unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss.

Intangible Assets and Goodwill — Intangible assets consist primarily of commodity sales and purchase contracts and relationships, which are amortized on a straight-line basis over the term of the contract or anticipated relationship, ranging from one to 25 years. Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business.

We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

Long-Lived Assets — We evaluate whether the carrying value of long-lived assets, excluding goodwill, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;
- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; and
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset’s carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management’s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Upon classification as held for sale, a long-lived asset is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset is separately presented on the consolidated balance sheet.

If an asset held for sale or sold (1) has clearly distinguishable operations and cash flows, generally at the plant level, (2) has direct cash flows of the held for sale or sold component that will be eliminated (from the perspective of the held for sale or sold component), and (3) if we are unable to exert significant influence over the disposed component, then the related results of operations for the current and prior periods, including any related impairments and gains or losses on sales are reflected as income from discontinued operations in the consolidated statement of operations and comprehensive income. If an asset held for sale or sold does not have clearly distinguishable operations and cash flows, impairments and gains or losses on sales are recorded as gain on sale of assets in the consolidated statement of operation and comprehensive income.

Unamortized Debt Premium, Discount and Expense — Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the terms of the debt using the effective interest method. These premiums and discounts are recorded on the consolidated balance sheet within long-term debt. These unamortized expenses are recorded on the consolidated balance sheet as other non-current assets.

Distributions — Under the terms of the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and ConocoPhillips based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member with a minimum of each member’s tax, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and ConocoPhillips. During the year ended December 31, 2007 we paid distributions of $497 million based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due.

Our board of directors determines the amount of the quarterly dividend to be paid to Spectra Energy and ConocoPhillips, by considering net income, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. During the year ended December 31, 2007 we paid dividends of $867 million to the members. The $867 million paid during the year ended December 31, 2007 is comprised of proportionate distributions to Spectra Energy and ConocoPhillips, allocated in accordance with our partners' respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units and subordinated units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement. Our limited partner interest in DCP Partners primarily consists of subordinated units and common units. The subordinated units are entitled to receive the minimum quarterly distribution only after DCP Partners' common unitholders have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in DCP Partners' partnership agreement, have been met. The subordination period has an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert to common units in February 2008 and permits the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in DCP Partners' partnership agreement are satisfied. During the year ended December 31, 2007 DCP Partners paid distributions of approximately $25 million to its public unitholders. In addition to our 33.9% limited partnership interests we hold a 1.5% general partnership interest, as well as incentive distribution rights, which entitle us to receive an increasing share of available cash when pre-defined distribution targets are achieved.

Stock-Based Compensation — Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Accounting for Sales of Units by a Subsidiary — We account for sales of units by a subsidiary by recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. As a result, we have deferred approximately $228 million of gain on sale of common units in DCP Partners, which is included in other long-term liabilities in the consolidated balance sheet. This gain is comprised of approximately $36 million related to DCP Partners' private placement in August 2007, $43 million related to DCP Partners' private placement in June 2007, and approximately $149 million related to DCP Partners' initial public offering in December 2005. We will recognize this gain in earnings upon conversion of all of our subordinated units in DCP Partners to common units.

Income Taxes — We are structured as a limited liability company, which is a pass-through entity for U.S. income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities.

Recent Accounting Pronouncements — **SFAS No. 160, "*Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51*," or SFAS 160.** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

SFAS No. 141(R) "*Business Combinations (revised 2007)*," or SFAS 141(R). In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

SFAS No. 159 "*The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115*," or SFAS 159. In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated financial position.

SFAS No. 157 "*Fair Value Measurements*," or SFAS 157. In September 2006, the FASB issued SFAS 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we estimate a cumulative effect of transition adjustment of an after-tax increase to members' equity of approximately $8 million. This transition adjustment will directly affect the beginning balance of members' equity.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While, we have adopted SFAS 157 for all financial assets and liabilities (primarily as a result of derivative trading activity) effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

FASB Interpretation No. 48 "*Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement 109*," or FIN 48. In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, "*Accounting for Income Taxes.*" FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a material impact on our consolidated financial position.

2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets — On August 29, 2007, we acquired the stock of Momentum Energy Group, Inc., or MEG, for approximately $635 million plus closing adjustments of approximately $11 million. The results of MEG's operations have been included in the consolidated financial statements since that date. As a result of the acquisition, we expanded our operations into the Fort Worth, Piceance and Powder River producing basins, thus diversifying our business into new areas. We funded our portion of this acquisition with a 364-day bridge loan for $450 million, which was paid off in September 2007 with proceeds from the issuance of the $450 million principal amount of 6.75% Senior Notes, as well as cash on hand. See further discussion of this transaction in the Contributions to DCP Partners section below.

Under the purchase method of accounting, the assets and liabilities of MEG were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $135 million. The goodwill amount recognized relates primarily to projected growth in the Fort Worth and Piceance producing basins due to significant natural gas reserves and high level of drilling activity. We expect all of the goodwill to be tax deductible. Because of the recency of this transaction, however, the values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained. When finalized, material adjustments to goodwill may result.

The purchase price allocation is as follows (millions):

Cash	$ 42
Receivables	23
Other assets	2
Property, plant and equipment	278
Intangible assets	254
Goodwill	135
Payables	(18)
Other liabilities	(27)
Current debt	(20)
Minority interest	(23)
Total allocation of purchase price	$ 646

In May 2007, DCP Partners acquired certain gathering and compression assets located in southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181 million.

In the fourth quarter of 2005, we entered into an agreement to purchase certain pipeline and compressor station assets in Kansas, Oklahoma and Texas for approximately $50 million, which are regulated by the Federal Energy Regulatory Commission, or FERC. We did not receive regulatory approval from the FERC to purchase the assets as non-jurisdictional gathering, but we have filed with the FERC for a certificate to operate as an interstate pipeline. This acquisition is expected to close in 2008.

Contributions to DCP Partners

MEG — Concurrent with our acquisition of the stock of MEG in August 2007, DCP Partners acquired certain subsidiaries of MEG from us for $166 million plus post-closing purchase price adjustments of approximately $9 million. These subsidiaries of MEG own assets in the Piceance Basin, including a 70% operated interest in the Collbran Valley Gas Gathering system joint venture in western Colorado, assets in the Powder River Basin, including the Douglas gas gathering system in Wyoming. DCP Partners financed this transaction with $120 million of revolver and term loan borrowings under DCP Partners’ Amended Credit Agreement, the issuance of common units through a private placement with certain institutional inventors and cash on hand. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We will continue to operate these assets and these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

DCP East Texas Holdings, LLC and Discovery Producer Services LLC — In July 2007, we contributed to DCP Partners our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery and a derivative instrument, for aggregate consideration of $244 million in cash, including $1 million for net working capital and other adjustments, $27 million in common units and $1 million in general partner equivalent units. We own the remaining 75% limited liability company interest in East Texas, while third parties still own the other 60% limited liability interest in Discovery. DCP Partners financed the cash portion of this transaction with borrowings under its existing credit facility. We will continue to operate East Texas and both of these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

3. Agreements and Transactions with Affiliates

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services to Spectra Energy and their subsidiaries. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

Included in the consolidated balance sheet in other non-current assets—affiliates as of December 31, 2007, are insurance recovery receivables of $27 million and included in accounts receivable—affiliates as of December 31, 2007 are other receivables of $2 million. Prior to January 2, 2007, these receivables were from an insurance provider that is a subsidiary of Duke Energy. In connection with the Spectra spin, Spectra Energy is responsible for these insurance liabilities.

Duke Energy

In connection with the Spectra spin, Duke Energy is not considered a related party for reporting periods after January 2, 2007.

Services Agreement — Under a services agreement, Duke Energy and certain of its subsidiaries provided us with various staff and support services, including information technology products and services, payroll, employee benefits, property taxes, media relations, printing and records management. Additionally, we used other Duke Energy services subject to hourly rates, including legal, insurance, internal audit, tax planning, human resources and security departments.

In connection with the Spectra spin, as of December 31, 2007, our corporate operations, Spectra Energy, or third party service providers have assumed responsibility for all services previously provided to us by Duke Energy.

ConocoPhillips

Long-term NGLs Purchases Contract and Transactions — We sell a portion of our residue gas and NGLs to ConocoPhillips and its subsidiaries, including Chevron Phillips Chemical Company LLC, or CP Chem, a 50% equity investment of ConocoPhillips. In addition, we purchase raw natural gas from ConocoPhillips. Under the NGL Output Purchase and Sale Agreements, or the NGL Agreements, with ConocoPhillips and CP Chem, ConocoPhillips and CP Chem have the right to purchase at index-based prices substantially all NGLs produced by our various processing plants located in the Mid-Continent and Permian Basin regions, and the Austin Chalk area, which include approximately 40% of our total NGL production. The NGL Agreements also grant ConocoPhillips and CP Chem the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. The primary terms of the agreements are effective until January 1, 2015. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips and CP Chem in the ordinary course of business.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

Estimates related to affiliates

Revenue for goods and services provided but not invoiced to affiliates is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. Actual invoices for the current month are issued in the following month and differences from estimated amounts are recorded. There are no material differences from the actual amounts invoiced subsequent to quarter end relating to estimated revenues and purchases recorded at December 31, 2007.

4. Inventories

Inventories were as follows:

	December 31, 2007 (millions)
Natural gas held for resale	$ 39
NGLs	78
Total inventories	$ 117

5. Property, Plant and Equipment

Property, plant and equipment by classification was as follows:

	Depreciable Life	December 31, 2007 (millions)
Gathering	15 - 30 years	$ 3,233
Processing	25 - 30 years	2,030
Transportation	25 - 30 years	1,224
Underground storage	20 - 50 years	121
General plant	3 - 5 years	153
Construction work in progress		347
		7,108
Accumulated depreciation		(2,665)
Property, plant and equipment, net		$ 4,443

Interest capitalized on construction projects in 2007 was approximately $4 million. At December 31, 2007 we had non-cancelable purchase obligations of approximately $9 million for capital projects to be completed in 2008.

6. Goodwill and Intangible Assets

The changes in carrying amount of goodwill are as follows:

	December 31, 2007 (millions)
Goodwill, beginning of period	$ 421
Goodwill acquired	135
Goodwill, end of period	$ 556

The increase in goodwill during 2007 consists of the amount that we recognized in connection with our acquisition of MEG.

We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment test, as of August 31, 2007 indicated that our reporting units' fair values exceed their carrying or book values. Accordingly, no impairment of goodwill is indicated.

Intangible assets consist primarily of commodity sales and purchase contracts and relationships. The gross carrying amount and accumulated amortization for intangible assets are as follows:

	December 31, 2007 (millions)
Gross carrying amount	$ 398
Accumulated amortization	(86)
Intangible assets, net	$ 312

Intangible assets increased as a result of the Southern Oklahoma and MEG acquisitions, through which $12 million and $254 million, respectively, of intangible assets were acquired. The remaining amortization periods range from less than one year to 25 years, with a weighted average remaining period of approximately 21 years.

Estimated amortization for these contracts for the next five years and thereafter is as follows as of December 31, 2007:

Estimated Amortization (millions)	
2008	$ 21
2009	20
2010	19
2011	18
2012	18
Thereafter	216
Total	$ 312

7. Investments in Unconsolidated Affiliates

We have investments in the following unconsolidated affiliates accounted for using the equity method:

	2007 Ownership	December 31, 2007 (millions)
Discovery Producer Services LLC	40.00%	$ 118
Main Pass Oil Gathering Company	66.67%	43
Mont Belvieu I	20.00%	12
Sycamore Gas System General Partnership	48.45%	11
Tri-States NGL Pipeline, LLC	16.67%	9
Black Lake Pipe Line Company	50.00%	7
Other unconsolidated affiliates	Various	4
Total investments in unconsolidated affiliates		$ 204

Discovery Producer Services LLC — Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several laterals expanding their presence in the Gulf. The deficit between the carrying amount of the investment and the underlying equity of Discovery of $44 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Discovery.

Main Pass Oil Gathering Company — We own a 66.67% interest in Main Pass, a joint venture whose primary operation is a crude oil gathering pipeline system in the Main Pass East and Viosca Knoll Block areas in the Gulf of Mexico. Since Main Pass is not a variable interest entity, and we do not have the ability to exercise control, we continue to account for Main Pass under the equity method. The excess of the carrying amount of the investment over the underlying equity of Main Pass of $12 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Main Pass.

Mont Belvieu I — Mont Belvieu I owns a 150 MBbl/d fractionation facility in the Mont Belvieu, Texas Market Center. The deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I of $10 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Mont Belvieu I.

Sycamore Gas System General Partnership — Sycamore Gas System General Partnership, or Sycamore, is a partnership formed for the purpose of constructing, owning and operating a gas gathering and compression system in Carter County, Oklahoma. The excess of the carrying amount of the investment over the underlying equity of Sycamore of $7 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Sycamore.

Tri-States NGL Pipeline, LLC — Tri-States NGL Pipeline, LLC, or Tri-States, owns 169 miles of NGL pipeline, extending from a point near Mobile Bay, Alabama to a point near Kenner, Louisiana. The deficit between the carrying amount of the investment and the underlying equity of Tri-States of $3 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Tri-States. We own less than 20% interest in this Partnership, however, we exercise significant influence, therefore, this investment is accounted for under the equity method of accounting.

Black Lake Pipe Line Company — Black Lake Pipe Line Company, or Black Lake, owns a 317 mile long NGL pipeline, with a current capacity of approximately 40 MBbl/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. The NGLs are transported to Mont Belvieu fractionators. The deficit between the carrying amount of the investment and the underlying equity of Black Lake of $7 million at December 31, 2007 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Black Lake.

The following summarizes combined balance sheet information of unconsolidated affiliates:

	December 31, 2007 (millions)
Balance sheet:	
Current assets	$ 123
Non-current assets	638
Current liabilities	(49)
Non-current liabilities	(19)
Net assets	$ 693

8. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. Considerable judgment is required, however, in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

	December 31, 2007	
	Carrying Amount	Estimated Fair Value
	(millions)	
Short-term investments	$ 9	$ 9
Restricted investments	$ 101	$ 101
Accounts receivable	$ 1,688	$ 1,688
Accounts payable	$ 1,675	$ 1,675
Net unrealized (losses) and gains on mark-to-market and hedging instruments	$ (97)	$ (97)
Long-term debt	$ 2,930	$ 3,030

The fair value of short-term investments, restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

The estimated fair values of current debt, including current maturities of long-term debt, and long-term debt, with the exception of DCP Partners' long-term debt, are determined by prices obtained from market quotes. The carrying value of DCP Partners' long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

9. Asset Retirement Obligations

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes changes in the asset retirement obligation, included in other long-term liabilities in the consolidated balance sheet:

	December 31, 2007 (millions)
Balance, beginning of period	$ 52
Accretion expense	4
Liabilities incurred	4
Liabilities settled	—
Other	(1)
Balance, end of period	$ 59

10. Financing

Long-term debt was as follows:

	December 31, 2007 (millions)
Debt securities:	
Issued August 2000, interest at 7.875% payable semiannually, due August 2010	$ 800
Issued January 2001, interest at 6.875% payable semiannually, due February 2011	250
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200
Issued August 2000, interest at 8.125% payable semiannually, due August 2030	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450
DCP Partners' credit facility revolver, weighted-average interest rate of 5.47%, due June 2012 (a)	530
DCP Partners' credit facility term loan, interest rate of 5.05%, due June 2012	100
Fair value adjustments related to interest rate swap fair value hedges (b)	8
Unamortized discount	(8)
Long-term debt	$ 2,930

Debt Securities — In September 2007, we issued $450 million principal amount of 6.75% Senior Notes due 2037, or the 6.75% Notes, for proceeds of approximately $444 million, net of related offering costs. The 6.75% Notes mature and become due and payable on September 15, 2037. We will pay interest semiannually on March 15 and September 15 of each year, commencing March 15, 2008. The proceeds of this offering were used to pay off the 364-Day Bridge Loan described below.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. Interest is payable semiannually. The debt securities are unsecured and are redeemable at our option.

Credit Facilities with Financial Institutions — We have a $450 million revolving credit facility, or the Facility, which is used to support our commercial paper program, and for working capital and other general corporate purposes. In October 2006, we amended the Facility to modify the change of control provisions to allow for the Spectra spin, to extend the maturity to April 29, 2012, to amend the pricing, to remove the interest coverage covenant and to incorporate other minor revisions. Any outstanding borrowings under the Facility at maturity may, at our option, be converted to an unsecured one-year term loan. The Facility requires us to maintain at all times a debt to total capitalization ratio of less than or equal to 60%. Draws on the Facility bear interest at a rate equal to, at our option and based on our current debt rating, either (1) LIBOR plus 0.23% per year for the initial 50% usage or LIBOR plus 0.28% per year if usage is greater than 50% or (2) the higher of (a) the Wachovia Bank prime rate per year and (b) the Federal Funds rate plus 0.5% per year. The Facility incurs an annual facility fee of 0.07% based on our credit rating on the drawn and undrawn portions. The Facility may be used for letters of credit. As of December 31, 2007 there were no borrowings or commercial paper outstanding, and there were approximately $5 million in letters of credit outstanding.

On June 21, 2007, DCP Partners entered into the Amended and Restated Credit Agreement, or DCP Partners' Amended Credit Agreement, that replaced their existing credit agreement, or DCP Partners' Credit Agreement, which consists of a $600 million revolving credit facility and a $250 million term loan facility. At December 31, 2007, DCP Partners had less than $1 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2007.

Under DCP Partners' Amended Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon the leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to; (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%.

DCP Partners' Amended Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by DCP Partners' Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. DCP Partners' Amended Credit Agreement also requires DCP Partners to maintain an interest coverage ratio (the ratio of consolidated EBITDA to consolidated interest expense, in each case as is defined by DCP Partners' Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loans

In August 2007, we entered into a 364-day bridge loan, or the 364-Day Bridge Loan, which provided for borrowings of up to $450 million, and had terms and conditions substantially similar to those of our Facility. We borrowed $450 million to fund a portion of the acquisition of the stock of MEG, and then paid it off in September with proceeds from the issuance of the 6.75% Notes.

In May 2007, DCP Partners entered into a two-month bridge loan, or the Two-Month Bridge Loan, which provided for borrowings up to $100 million, and had terms and conditions substantially similar to those of DCP Partners' Credit Agreement. In conjunction with DCP Partners entering into the Two-Month Bridge Loan, DCP Partners' Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100 million, which was due and payable no later than August 9, 2007. DCP Partners used borrowings of $88 million from the Two-Month Bridge Loan to partially fund the acquisition of assets from Anadarko. The remaining $12 million available for borrowing on the Two-Month Bridge Loan was not utilized. DCP Partners used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88 million outstanding on the Two-Month Bridge Loan in June 2007.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2007:

	Debt Maturities (millions)
2010	$ 800
2011	250
2012	630
Thereafter	1,258
	2,938
Unamortized discount	(8)
Long-term debt	$ 2,930

11. Risk Management and Derivative Activities, Credit Risk and Financial Instruments

The impact of our derivative activity on our financial position is summarized below:

	December 31, 2007 (millions)
Commodity derivative instruments:	
Net deferred losses in AOCI	$ (1)
Interest rate derivative instruments:	
Net deferred losses in AOCI	$(10)
Interest rate fair value hedges:	
Unrealized gains	$ 8

For the year ended December 31, 2007, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Commodity Price Risk — Our principal operations of gathering, processing, compression, transportation and storage of natural gas, and the accompanying operations of fractionation, transportation, gathering, treating, processing, storage and trading and marketing of NGLs create commodity price risk exposure due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Energy Trading (Market) Risk — Certain of our subsidiaries are engaged in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

Interest Rate Risk — We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to hedge interest rate risk associated with our debt. Our primary goals include (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates based on historical rates.

Credit Risk — Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem under an existing 15-year contract, which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use master collateral agreements to mitigate credit exposure. Collateral agreements provide for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

As of December 31, 2007, we held deposits, of $57 million included in other current liabilities, and letters of credit of $97 million, from counterparties to secure their future performance of financial or physical contracts. We had deposits with counterparties $45 million, included in other current assets, of such collateral to secure our obligations to provide future services or to perform under financial contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Commodity Derivative Activity — Our operations of gathering, processing, and transporting natural gas, and the related operations of transporting and marketing of NGL create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGL, natural gas and crude oil.

We manage our commodity derivative activities in accordance with our risk management policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Commodity Cash Flow Protection Activities — DCP Partners uses NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGL, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statement of operation and comprehensive income in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas and petroleum products through December 2011, as the hedged transactions impact earnings. Deferred net losses of less than $1 million are expected to be reclassified into earnings during the next

12 months. Subsequent to July 1, 2007, the changes in fair value of these financial derivatives are included in trading and marketing gains and losses in the consolidated statement of operations and comprehensive income.

As of December 31, 2007, DCP Partners has mitigated a portion of our expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from gathering and processing operations through 2013 with natural gas, NGL and crude oil derivatives.

Commodity Fair Value Hedges — Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) and market locks (fixed price gas sales) to reduce our cash flow exposure to fixed price risk via swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index based).

Normal Purchases and Normal Sales — If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Commodity Derivatives — Trading and Marketing — Our trading and marketing program is designed to realize margins related to fluctuations in commodity prices and basis differentials, and to maximize the value of certain storage and transportation assets. Certain of our subsidiaries are engaged in the business of trading energy related products and services including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage our trading and marketing portfolio with strict policies, which limit exposure to market risk, and require daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk.

Interest Rate Cash Flow Hedges —DCP Partners mitigates a portion of their interest rate risk with interest rate swaps, which reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert the interest rate associated with an aggregate of $425 million of the variable rate exposure to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheet. As of December 31, 2007, $2 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Interest Rate Fair Value Hedges — In August 2003, we entered into two interest rate swaps to convert $100 million of fixed-rate debt securities issued in August 2000 to floating rate debt. These interest rate fair value hedges are at a floating rate based on six-month LIBOR, which is re-priced semiannually through 2030. The swaps meet conditions which permit the assumption of no ineffectiveness. As such, for the life of the swaps no ineffectiveness will be recognized.

12. Non-Controlling Interest

Non-controlling interest represents the ownership interests of third-party entities in net assets of various equity method investments in consolidated affiliates, including ownership interest of DCP Partners' public unitholders in net assets of DCP Partners through DCP Partners' publicly traded common units, and in net assets of DCP East Texas Holdings, LLC, of which DCP Partners acquired a 25% equity interest in July 2007 as well as Collbran Valley Gas Gathering, which was acquired in conjunction with the MEG acquisition in August 2007. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party and affiliate investors' interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party and affiliate investors.

13. Stock-Based Compensation

Key components of our stock-based compensation plans are as follows:

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2007 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream's 2006 Plan:				
Relative Performance Units (RPUs)	8	$ 1	64%	6
Strategic Performance Units (SPUs)	3	$ 4	12%/32%	2
Phantom Units	5	$ 1	19%	4
DCP Partners' Phantom Units	3	$ 1	12%/32%	1
DCP Partners' Plan:				
Performance Units	3	$ 1	0%	2
Phantom Units	3	$ —	0%	1
Duke Energy's 1998 Plan and Spectra Energy's 2007 LTIP Plan:				
Stock Options (no activity in 2007)	0-10	$ —	NA	—
Stock Based Performance Awards	3	$ —	0-8%	1
Phantom Awards	1-5	$ —	4-5%	2
Other Stock Awards	1-5	$ —	NA	—

DCP Midstream, LLC Long-Term Incentive Plan, or 2006 Plan — Under our 2006 Long Term Incentive Plan, or 2006 Plan, equity instruments may be granted to our key employees. The 2006 Plan provides for the grant of Relative Performance Units, or RPU's, Strategic Performance Units, or SPU's, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Duke Energy, Spectra Energy and DCP Partners. The weighting varies depending on when the units were granted. The DCP Partners' Phantom Units constitute a notional unit equal to the fair value of DCP Partners' common units. Each award provides for the grant of dividend or distribution equivalent rights. The 2006 Plan is administered by the compensation committee of our board of directors. We first granted awards under the 2006 Plan during the second quarter of 2006. All awards are subject to cliff vesting.

Relative Performance Units — The number of RPU's that will ultimately vest range from 0% to 200% of the outstanding RPU's, depending on the achievement of specified performance targets over a three year period ending in January 2009 and 2010, respectively, for units granted in 2006 and 2007. The final performance payout is determined by the compensation committee of our board of directors. After the performance period, vesting occurs over five years, at the end of which the value is based on the participant's investment elections during the deferral period. Dividend or distribution equivalent rights will be paid in cash at the end of the performance period. The following tables presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	44,080	$42.89	
Granted	42,340	$43.98	
Forfeited	(21,237)	$43.55	
Vested or paid in cash	(3,016)	$42.86	
Outstanding at December 31, 2007	62,167	$43.41	$54.84
Expected to vest	33,041	$43.41	$54.84

Strategic Performance Units —The number of SPU's that will ultimately vest range from 0% to 150% of the outstanding SPU's, depending on the achievement of specified performance targets over a three year period ending on December 31, 2008 and 2009, respectively, for units granted in 2006 and 2007. The final performance payout is determined by the compensation committee of our board of directors. Dividend or distribution equivalent rights will be paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	84,960	$42.92	
Granted	86,380	$44.04	
Forfeited	(28,305)	$43.51	
Vested or paid in cash	(3,016)	$42.86	
Outstanding at December 31, 2007	140,019	$43.49	$54.84
Expected to vest	127,432	$43.49	$54.84

The estimate of RPU's and SPU's that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

Phantom Units —Dividend or distribution equivalent rights are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	17,460	$42.95	
Granted	19,450	$44.10	
Forfeited	(2,930)	$43.42	
Vested or paid in cash	(180)	$42.86	
Outstanding at December 31, 2007	33,800	$43.57	$54.84
Expected to vest	29,931	$43.57	$54.84

DCP Partners' Phantom Units — The distribution equivalent rights are paid quarterly in arrears. The following table presents information related to the DCP Partners' Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	47,750	$28.60	
Granted	13,500	$50.57	
Forfeited	(2,000)	$28.60	
Vested or paid in cash	(7,500)	$28.60	
Outstanding at December 31, 2007	51,750	$34.33	$45.95
Expected to vest	46,080	$34.33	$45.95

DCP Partners' Long-Term Incentive Plan, or DCP Partners' Plan — Under DCP Partners' Long Term Incentive Plan, or DCP Partners' Plan, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners' Plan provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 common units may be delivered pursuant to awards under the DCP Partners' Plan. Awards that are canceled, forfeited or withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations are available for delivery pursuant to other awards. The DCP Partners' Plan is administered by the compensation committee of DCP Midstream GP, LLC's board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to the directors in conjunction with the initial public offering, which are subject to graded vesting provisions.

Awards granted to directors are accounted for as equity-based awards and all other awards are accounted for as liability awards.

Performance Units — The number of Performance Units that will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance percentage payout is determined by the compensation committee of DCP Partners' board of directors. The DERs will be paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2007, 28,350 units are expected to vest on December 31, 2008 and 27,150 units are expected to vest on December 31, 2009. The following tables presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	23,090	$26.96	
Granted	29,610	$37.29	
Forfeited	(5,740)	$31.39	
Outstanding at December 31, 2007	46,960	$32.93	$45.95
Expected to vest (a)	55,500	$32.93	$45.95

(a) Based on our December 31, 2007 estimated achievement of specified performance targets, the number of performance units granted in 2006 that will ultimately vest is estimated at 143% of the targeted units granted.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

Phantom Units — In conjunction with their initial public offering, in January 2006 DCP Partners awarded Phantom Units to key employees, and to directors who are not officers or employees of DCP Midstream GP, LLC, or its affiliates who perform services for DCP Partners. Of the remaining Phantom Units outstanding at December 31, 2007, 2,001 units are expected to vest on January 3, 2008 and 17,698 units are expected to vest on January 3, 2009.

In 2007, DCP Partners granted 4,500 Phantom Units pursuant to the DCP Partners' Plan, to directors who are not officers or employees of affiliates of DCP Midstream as part of their annual director fees for 2007. Of these Phantom Units, 4,000 units vested during 2007 and 500 units are expected to vest on February 7, 2008.

The DERs are paid quarterly in arrears.

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	24,700	$24.05	
Granted	4,500	$42.90	
Forfeited	(2,333)	$24.05	
Vested	(6,668)	$35.23	
Outstanding at December 31, 2007	20,199	$24.56	$45.95
Expected to vest	20,199	$24.56	$45.95

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

During the year ended December 31, 2007, 2,668 units vested and were settled in cash for less than $1 million, and 4,000 units were settled with the issuance of limited partner units.

All awards issued under the 2006 Plan and the DCP Partners' Plan are intended to be settled in cash or stock upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of the relevant underlying securities at each measurement date.

Duke Energy 1998 Plan and Spectra Energy 2007 Long-Term Incentive Plan — Under the Duke Energy 1998 Plan, or the 1998 Plan, Duke Energy granted certain of our key employees stock options, stock-based performance awards, phantom stock awards and other stock awards to be settled in shares of Duke Energy's common stock, or the Stock-Based Awards. Upon execution of the 50-50 Transaction in July 2005, our employees incurred a change in status from Duke Energy employees to non-employees. As a result, we began accounting for these awards using the fair value method. No awards have been and we do not expect to settle any awards granted under the 1998 Plan with cash.

In connection with the Spectra spin, one replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the Spectra spin. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy Stock-Based Awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the Spectra Energy 2007 Long-Term Incentive Plan, or the Spectra Energy 2007 LTIP.

The Spectra Energy 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the Spectra Energy 2007 LTIP. Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

Stock Options — Under the 1998 Plan, the exercise price of each option granted could not be less than the market price of Duke Energy's common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting.

The following table shows information regarding options to purchase Duke Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at December 31, 2006	2,101,062			
Effect of conversion	(258,058)			
Outstanding at January 1, 2007	1,843,004	$17.85	4.1	
Exercised	(21,960)	$13.89		
Forfeited	(5,088)	$22.90		
Outstanding at December 31, 2007	1,815,956	$17.89	3.2	$ 7
Exercisable at December 31, 2007	1,815,956	$17.89	3.2	$ 7

The total intrinsic value of options exercised during the year ended December 31, 2007 was less than $1 million.

The following table shows information regarding options to purchase Spectra Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at December 31, 2006	—			
Effect of conversion	1,066,595			
Outstanding at January 1, 2007	1,066,595	$ 26.43	4.1	
Exercised	(73,920)	$ 17.84		
Forfeited	(55,427)	$ 31.78		
Outstanding at December 31, 2007	937,248	$ 26.80	3.2	$ 3
Exercisable at December 31, 2007	937,248	$ 26.80	3.2	$ 3

The total intrinsic value of options exercised during the year ended December 31, 2007 was approximately $1 million.

Stock-Based Performance Awards — There were no stock-based performance awards granted during the year ended December 31, 2007.

The following tables summarize information about stock-based performance awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2006	301,618		
Effect of conversion	(128,213)		
Outstanding at January 1, 2007	173,405	$15.58	
Forfeited	(40)	$15.38	
Outstanding at December 31, 2007	173,365	$15.58	$20.17
Expected to vest	173,325	$15.58	$20.17

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2006	—		
Effect of conversion	184,083		
Outstanding at January 1, 2007	184,083	$20.93	
Vested	(83,309)	$18.30	
Forfeited	(14,091)	$20.42	
Outstanding at December 31, 2007	86,683	$23.54	$25.82
Expected to vest	80,048	$23.54	$25.82

The total fair value of the performance stock awards that vested during the year ended December 31, 2007 was approximately $2 million. No awards were granted, vested or canceled during the year ended December 31, 2007.

Phantom Stock Awards — There were no phantom stock awards granted during the year ended December 31, 2007.

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2006	164,688		
Effect of conversion	(52,664)		
Outstanding at January 1, 2007	112,024	$15.59	
Vested	(29,190)	$15.54	
Forfeited	(5,624)	$15.38	
Outstanding at December 31, 2007	77,210	$15.62	$20.17
Expected to vest	73,960	$15.62	$20.17

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2006	—		
Effect of conversion	104,171		
Outstanding at January 1, 2007	104,171	$21.31	
Vested	(59,258)	$19.66	
Forfeited	(6,308)	$22.81	
Outstanding at December 31, 2007	38,605	$23.60	$25.82
Expected to vest	36,487	$23.60	$25.82

The total fair value of the phantom stock awards that vested during the year ended December 31, 2007 was approximately $2 million. No awards were granted or canceled during the year ended December 31, 2007.

Other Stock Awards — There were no other stock awards granted during the year ended December 31, 2007.

The following tables summarize information about other stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2007	21,600	$12.38	
Vested	(21,600)	$12.38	
Forfeited	—	$ —	
Outstanding at December 31, 2007	—	$ —	$—
Expected to vest	—	$ —	$—

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2006	—		
Effect of conversion	10,800		
Outstanding at January 1, 2007	10,800	$18.71	
Vested	(10,800)	$18.71	
Forfeited	—	$ —	
Outstanding at December 31, 2007	—	$ —	$—
Expected to vest	—	$ —	$—

The total fair value of the other stock awards that vested during the year ended December 31, 2007 was not significant. No awards were granted or canceled during the year ended December 31, 2007.

14. Benefits

All Company employees who are 18 years old and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contribute a range of 4% to 7% of each eligible employee's qualified earnings to the retirement plan, based on years of service. Additionally, we match employees' contributions in the 401(k) plan up to 6% of qualified earnings.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP's Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf. All amounts contributed to or earned by the plan's investments are held in a trust account for the benefit of the participants. The trust and the liability to the participants are part of our general assets and liabilities, respectively.

15. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for United States income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state and local taxes of the limited liability company and other subsidiaries.

In May 2006, the State of Texas enacted a margin-based franchise tax law that replaced the existing franchise tax, commonly referred to as the Texas margin tax. The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. As a result of the change in Texas franchise law, our status in the state of Texas changed from non-taxable to taxable. Since the Texas margin tax is considered an income tax, in the second quarter of 2006 we recorded a non-current deferred tax liability of $18 million. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year. Accordingly, we recorded current tax expense for the Texas margin tax, beginning in 2007.

Temporary differences for our federal deferred tax assets of $7 million primarily relate to basis differences between property, plant and equipment, and investments in consolidated affiliates. Temporary differences for our state deferred tax liabilities of $16 million primarily relate to basis differences between property, plant and equipment.

Our effective tax rate differs from statutory rates, primarily due to our being structured as a limited liability company, which is a pass-through entity for United States income tax purposes, while being treated as a taxable entity in certain states.

16. Commitments and Contingent Liabilities

Litigation — The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. Although the industry has seen these types of cases before, they were typically brought by a single plaintiff or small group of plaintiffs. A number of these cases are now being brought as class actions. We are currently named as defendants in some of these cases. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These class actions, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving DCP Partners' Minden processing plant that dates back to August 2000. El Paso claims damages, including interest, in the amount of $6 million in the litigation, the bulk of which stems from audit claims under our commercial contract. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated financial position.

In October 2007, we settled a lawsuit alleging migration of acid gas from a storage formation into a third party producing formation. Pending regulatory approval, we will obtain the rights to the producing formation. This matter did not have a material adverse effect upon our consolidated financial position.

General Insurance — Midstream's insurance coverage is carried with an affiliate of ConocoPhillips and third party insurers. Midstream's insurance coverage includes: (1) general liability insurance covering third party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

During the third quarter of 2004, certain assets, located in the Gulf Coast, were damaged as a result of hurricane Ivan. Also, during the third quarter of 2005, hurricanes Katrina and Rita forced us to temporarily shut down our operations at certain assets located in Alabama, Louisiana, Texas and New Mexico. Several of our assets sustained property damage, including some of our operating equipment on a platform in the Gulf of Mexico. A portion of the resulting lost revenues and property damages were covered by our insurance, subject to applicable deductibles. The financial impact of hurricanes has increased market rates for insurance coverage; however, these increases did not have a material adverse effect on our consolidated financial position. Insurance recovery receivables related to these hurricanes are detailed in Note 3.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated financial position.

On July 20, 2006, the State of New Mexico Environment Department issued Compliance Orders to us that list air quality violations during the past five years at six of our owned or operated facilities in New Mexico. The orders allege a number of violations related to excess emissions beginning January 2001, and further require us to install flares for smokeless operations and to use the flares only for emergency purposes. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated financial position.

Other Commitments and Contingencies — In June 2007, DCP Partners entered into a private placement agreement with a group of institutional investors for $130 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $129 million, net of offering costs. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In January 2008, DCP Partners' registration statement on Form S-3 to register the common limited partner units represented in the private placement agreements was declared effective by the Securities and Exchange Commission.

We utilize assets under operating leases in several areas of operations. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term. Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2008	$ 24
2009	19
2010	18
2011	17
2012	15
Thereafter	31
Total gross payments	124
Sublease receipts	(1)
Total net payments	$ 123

17. Guarantees and Indemnifications

We have signed a corporate guaranty, pursuant to which we are the guarantor of a maximum of approximately $1 million of construction obligations as of December 31, 2007. The guaranty will expire upon completion and payment for construction of a pipeline expected to be completed during 2008. The fair value of this guarantee is not significant to our consolidated results of operations, financial position or cash flows.

We periodically enter into agreements for the acquisition or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, or other liabilities related to the assets being acquired or divested. Claims may be made by third parties under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to five years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities.

18. Subsequent Events

On January 24, 2008, DCP Partners announced the declaration of a cash distribution of $0.57 per unit that was paid on February 14, 2008, to unitholders of record on February 7, 2008.

In January 2008, we received a distribution from Discovery of $11 million.

In February 2008, 50% of our subordinated units in DCP Partners, or 3,571,428 subordinated units, were converted to common units in accordance with the early termination provision in DCP Partners' partnership agreement.

Subsequent to December 31, 2007, DCP Partners executed a series of derivative instruments to mitigate a portion of its anticipated commodity exposure. DCP Partners entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and DCP Partners entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.