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, 2008

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, 2008, was approximately $582,555,000. 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 30, 2008.

As of February 23, 2009, there were outstanding 28,233,183 common limited partner units.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

DCP MIDSTREAM PARTNERS, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2008

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GLOSSARY OF TERMS

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

Bbl	barrel
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
MMscf	one million standard cubic feet
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 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;
- general economic, market and business conditions;
- 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;
- 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 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; and
- the amount of collateral we may be required to post from time to time in our transactions.

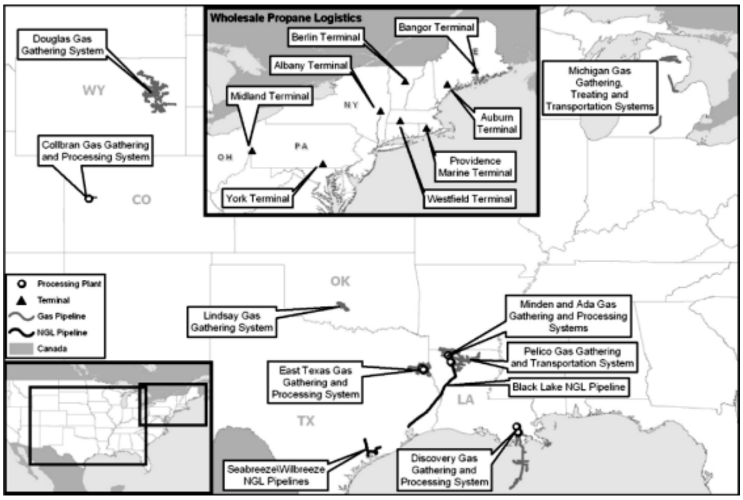
In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether 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 in August 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We completed our initial public offering on December 7, 2005. 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, which 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, which 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 approximately 900-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.
- 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 of 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 Michigan gathering and treating assets were acquired in October 2008 from Michigan Pipeline & Processing, LLC, or MPP. These assets consist of five natural gas treating plants and an approximately 155-mile gas gathering pipeline system with throughput capacity of 330 MMcf/d; an approximately 55-mile residue gas pipeline; a 75% interest in Jackson Pipeline Company, a partnership owning an approximately 25-mile residue pipeline, or Jackson Pipeline; and a 44% interest in the Litchfield pipeline, a 30-mile pipeline whereby we lease our undivided interest to ANR Pipeline Company through the use of a direct financing lease expiring in 2031.

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 was idled in 2007 to consolidate our operations, 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.

We have no revenue or segment profit or loss attributable to international activities.

For additional information on our segments, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and Note 18 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Our Business Strategies

Our primary business objective is to have sustained company profitability and a strong balance sheet. In addition, we would focus on profitable growth, thereby increasing 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.

The execution of our business strategies and our level of growth is dependent upon the availability and cost of capital, as well as the availability of growth opportunities. The recent turmoil in the capital markets has resulted in significantly higher costs of public debt and equity funds.

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 western Colorado, northern Louisiana, Michigan, southern Oklahoma, eastern Texas, northeastern Wyoming 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 commodity-based services, which together with our derivative activities, generate relatively stable cash flows. While certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a significant 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 fixed price 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 diversity of supply sources and 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 interest 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.

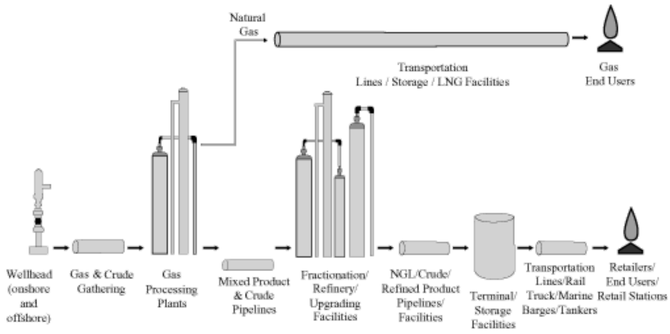
DCP Midstream, LLC has a significant interest in our partnership through its approximately 1% general partner interest in us, all of our incentive distribution rights and a 29% limited partner interest in us. We have entered into an omnibus agreement, or the Omnibus Agreement, with DCP Midstream, LLC 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, transporting and selling of natural gas, and the production, transporting and selling of NGLs.

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 from the natural gas that can have higher values as NGLs. NGLs are typically recovered by cooling the natural gas until the 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 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, which must also be removed to meet the quality standards for long-haul pipeline transportation. 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. 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. 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.

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 and the delivery of propane to retail distributors.

Production of Propane

Propane is extracted from the natural gas stream at processing plants, separated from 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 propane 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 seven states in the continental United States: Arkansas, Colorado, Louisiana, Michigan, 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, our Douglas system, and our Michigan gathering and treating assets. 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 4,500 miles of pipe, five processing plants, a treating plant, two NGL fractionation facilities and over 120,000 horsepower of compression capability. The processing plants that service our natural gas gathering systems include one cryogenic facility with approximately 115 MMcf/d of processing capacity, two refrigeration style facilities with approximately 165 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 20,000 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 830 MMcf/d from over 3,600 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 percent-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 percent-of-proceeds contracts due to the processing value 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, Minden, Collbran and Michigan 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)	2008 Operating Data Natural Gas Throughput (MMcf/d)(a)	NGL Production (Bbls/d)(a)
Minden	725	1	—	—	115	83	4,619
Ada	130	1	—	—	45	62	165
Pelico	600	—	—	—	—	171	—
Southern Oklahoma (Lindsay)	225	—	—	—	—	18	2,203
Collbran	30	1	—	—	120	90	486
Douglas	1,320	—	—	—	—	16	1,025
Michigan	265	—	—	—	—	75	—
Discovery	280	—	1	1	240(b)	170(b)	4,703(b)
East Texas	900	—	1	1	195(b)	153(b)	7,458(b)
Total	4,475	3	2	2	715	838	20,659

(a) Represents total volumes for 2008 divided by 366 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 the majority of the ethane when justified by market economics. This processing flexibility enables us to maximize the value of ethane for our customers. In 2002, we upgraded the Minden processing plant to enable greater ethane recovery and rejection capabilities. As part of that project, we reached an agreement with certain customers to receive 100% of the realized margin attributable to the incremental value of ethane recovered as an NGL from the natural gas stream when appropriate market conditions exist. The defined return on the initial investment for this ethane recovery upgrade was reached in 2007.

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 approximately 350 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 120 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 Occidental Petroleum Corporation (25%) and Delta Petroleum Corporation (5%), who are also producers on the system. The processing plant was expanded in 2008 to an operating capacity to 120 MMcf/d to accommodate expected increases in volumes. The Collbran system is currently undergoing a further expansion, which is scheduled to be completed in the third quarter of 2009, consisting of an additional 24-inch pipeline loop and compression at the Anderson Gulch site. The expansion, expected to be completed in 2009, would increase the pipeline capacity to over 200 MMcf/d and enable gas deliveries to the Meeker Plant through a downstream connection with Enterprise Products Partners LP, which is also expanding its system feeding its plant. The Collbran system is designed to ultimately have throughput capacity of over 600 MMcf/d depending on future production growth.

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 650 receipt points and delivers the gas to a third party for processing under a fee agreement. The Douglas system has approximately 16,000 horsepower of compression 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 acquired MPP on October 1, 2008. These assets consist of five natural gas treating plants and an approximately 155-mile gas gathering pipeline system with throughput capacity of 330 MMcf/d; an approximately 55-mile residue gas pipeline; a 75% interest in Jackson Pipeline Company, a partnership owning an approximately 25-mile residue pipeline; and a 44% interest in the Litchfield pipeline, a 30-mile pipeline whereby we lease our undivided interest to ANR Pipeline Company through the use of a direct financing lease expiring in 2031.

We have a 40% equity interest in Discovery and the remaining 60% is owned by Williams Partners, L.P. Discovery 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) an 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. The Discovery system is able to reject the majority of the ethane when justified by market economics.

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, Total E&P USA, Inc., and StatoilHydro ASA to construct an approximate 34-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 has a design capacity of approximately 200 MMcf/d. Chevron expects first production to 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 made capital contributions to us as reimbursement for remaining costs for the Tahiti pipeline lateral expansion, which were substantially completed in 2008.

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 of approximately 900 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 and NGL 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 Black Lake pipeline delivers NGLs to Mt. Belvieu. 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. NGLs produced from this system are delivered to Oneok Gas Transportation.

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 Michigan Antrim gas gathering and treating system delivers Antrim Shale gas to the South Chester Treating Complex. Antrim Shale natural gas requires treating in order to meet downstream gas pipeline quality specifications. The treated gas is transported to MichCon Gathering system from the tailgate of the plant. The Bay Area pipeline delivers fuel gas to a third party power plant owned by Consumers Energy. The Jackson Pipeline is operated by Consumers Energy and connects several intrastate pipelines with the Eaton Rapids gas storage facility. The Litchfield pipeline is operated by ANR Pipeline Company and facilitates receipts or deliveries between ANR Pipeline Company and the Eaton Rapids storage facility. All Michigan assets were acquired from MPP on October 1, 2008.

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 directly received or 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 percent-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 volume at Minden, Southern Oklahoma, Douglas and East Texas are processed under percent-of-proceeds contracts. Discovery has percent-of-proceeds contracts and fee-based contracts, as well as some keep-whole contracts. The majority of the contracts for our Pelico, Ada, Collbran and Michigan systems are fee-based agreements. Our gross margin generated from percent-of-proceeds contracts is directly correlated to the price of natural gas, NGLs and condensate.

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 in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue 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. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant 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 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. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. 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, subject to the availability of capital.

Our Terminals

Our operations include six propane rail terminals with aggregate storage capacity of 25 MBbls, one of which was idled in 2007 to consolidate our operations, 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, except for the York terminal where we own the land. The marine terminal is leased on a long-term lease agreement. Each of our rail terminals consist of two to three propane tanks with capacity of between 120,000 and 270,000 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 2008, our primary suppliers of propane included a subsidiary of DCP Midstream, LLC, Aux Sable Liquid Products LP and Spectra Energy. During 2007, our primary suppliers of propane included Shell International Trading and Shipping Company, Aux Sable Liquid Products LP and 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 May 2008, we entered into a long term contract with Spectra Energy that offers both product and shipping capabilities. The port where the 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

We operate our NGL Logistics business in the states of Louisiana and Texas.

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 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 2008 average throughput was approximately 31 MBbls/d.

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 recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. 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 2008 average throughput on the pipeline was approximately 17 MBbls/d. The Seabreeze pipeline was put into service in 2002 to deliver NGLs to a large processing plant with capacity of approximately 340 MMcf/d located in Matagorda County, and a NGL pipeline. The Seabreeze pipeline also delivered to a second plant, which was closed during 2008. The Seabreeze pipeline is the sole NGL pipeline for one processing plant and is the only delivery point for two NGL pipelines. One 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. In total seven processing plants produce NGLs that flow into the Seabreeze pipeline from processed 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 6 MBbls/d for 2008.

Black Lake Pipeline. The Black Lake pipeline has capacity of 40 MBbls/d and for 2008, average throughput on the Black Lake pipeline at our 45% interest was approximately 8 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 NGLs 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 NGLs from XTO Energy Inc.'s Cotton Valley processing plant. In addition, the Black Lake pipeline receives NGLs 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 47% of total throughput in 2008. The Black Lake pipeline generates revenues through a FERC-regulated tariff, and the average rate per barrel was $1.00 in 2008, $0.95 in 2007 and $0.94 in 2006.

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. This project was completed and cash distributions resumed during 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. Under this agreement, Williams has dedicated all of their respective NGL production from this processing plant 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 in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that requires 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 $2.0 million between 2009 and 2013 to implement integrity management program testing along certain segments of our natural gas transmission 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 agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

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. 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 transmission and regulated gathering 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.

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.

FERC Regulation of Operations

FERC 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 or 2007 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.

On March 21, 2008, FERC issued an NOPR to revise the Standards of Conduct to make them clearer and to refocus the rules on the areas where there is the greatest potential for affiliate abuse, or 2008 NOPR. The 2008 NOPR replaces the 2007 NOPR. The 2008 NOPR applies the Standards of Conduct to any interstate natural gas pipeline that conducts transportation transactions with an affiliate that engages in marketing functions. The definition of marketing function exempts sales from gathering and processing facilities.

On October 16, 2008, FERC issued Order No. 717 providing a final rule on the FERC Standards of Conduct that conforms to the U.S. Court of Appeals Decision. The final rule applies the Standards of Conduct to interstate natural gas pipelines that conduct transportation transactions with an affiliate that engages in marketing functions. Under the final rule, interstate pipeline transmission information is restricted from being disclosed to the affiliate’s marketing function employees. The definition of marketing function employees is limited to those employees engaged on a day-to-day basis in the sale for resale of natural gas in interstate commerce. The FERC Standards of Conduct do not apply to Discovery under the final rule.

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. On June 18, 2008, the MMS issued a final rule regarding open and nondiscriminatory access to pipelines on the OCS that is generally consistent with the NOPR. The final rule did institute a time limit of two years from the time of the denial of open access for initiating a formal complaint. The final rule is effective August 18, 2008. We do not expect that the final rule will affect our OCS operations.

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. On April 17, 2008, FERC issued a final policy statement regarding the appropriate composition of proxy groups. FERC concluded, among other things, that MLPs should be included in the Return on Equity or ROE proxy group for both oil and gas pipelines. FERC established a paper hearing for establishing the ROE for cases that were pending before FERC. The policy statement could result in the establishment of a higher ROE in future rate proceedings but the full effect is uncertain until the policy is applied.

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. On November 20, 2008, FERC terminated this proceeding and declined making any changes to the fuel retention practices of natural gas pipelines.

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. On March 21, 2008, FERC issued Order No. 710 implementing revisions to the forms, statements and reporting requirements of natural gas pipelines. The order is effective on January 1, 2008 and impacts the 2008 FERC Form 2 and subsequent Form 3-Qs. The final rule generally adopts the changes provided in the Reporting NOPR. While the revisions will require additional time in the development of the report, the impact of the final rule is not expected to be material to Discovery.

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. On June 19, 2008, FERC issued Order No. 712 implementing revised capacity release rules that revised the capacity release regulations consistent with the Capacity Release NOPR.

The most significant modification was to allow for capacity releases of one year or less to be awarded to the highest rate, without regard to the maximum rate. The impact of this rule to Discovery should be immaterial.

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. On November 20, 2008, FERC issued Order No. 720, a final rule adopting new regulations that require certain "major non-interstate pipelines" and interstate pipelines to publicly post certain operational and scheduling information. Interstate pipelines must post the volumes of no-notice transportation flows at each receipt and delivery point before 11:30 a.m. central clock time three days after the day of gas flow. The final rule requires interstate pipelines to post less information than under the proposed rule. The final rule does not apply to Discovery.

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.

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.

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. On November 20, 2008, FERC issued Order No. 720, a final rule adopting new regulations that require certain "major non-interstate pipelines" and interstate pipelines to publicly post certain operational and scheduling information. . Under the final rule, Order No. 720, "major non-interstate" gas pipelines must publicly post on a daily basis on an Internet web site (1) the design capacity of each receipt or delivery point that has a design capacity equal to or greater than 15,000 MMBtu/day, and (2) the amount scheduled at each such delivery point whenever capacity is scheduled. Order No. 720 defines a "major non interstate pipeline" as a company that is not an interstate pipeline and delivers annually more than fifty million MMBtu of natural gas measured in average deliveries for the previous three calendar years. The final rule exempts major non-interstate pipelines that lie entirely upstream of a processing, treatment, or dehydration plant. The implementation date is 150 days following the issuance of an order addressing the pending requests for rehearing. The Pelico and EastTrans Limited Partnership or East Trans systems are considered major non interstate pipelines and are required to comply with this rule. Compliance with this rule will result in additional administrative burdens related to the associated information technology costs.

On November 20, 2008, FERC issued an NOI to explore whether intrastate pipelines and Hinshaw pipelines providing interstate transportation and storage services should be required to post details of their transactions with shippers in a manner comparable to the posting requirements of interstate pipelines. Comments are due February 13, 2009. FERC's NOI is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

The Discovery interstate natural gas pipeline system filed with FERC on November 16, 2007 a rate case 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.

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 material, 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. 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 derivative 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.

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.

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. On April 17, 2008, FERC issued a final policy statement regarding the appropriate composition of proxy groups. FERC concluded, among other things, that MLPs should be included in the ROE proxy group for both oil and gas pipelines. FERC established a paper hearing for establishing the ROE for cases that were pending before FERC. The policy statement could result in the establishment of a higher ROE in future rate proceedings but the full effect is uncertain until the policy is applied.

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.

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. In addition, The Colorado Department of Public Health and Environment, or CDPHE, has alleged violations of the environmental permit at the Anderson Gulch Gas Plant, as a result of an inspection in January 2008. The allegations are primarily related to recordkeeping requirements. We are currently in settlement discussions with the CDPHE to resolve this matter. Aside from these enforcement matters, we believe that we are in material compliance with these requirements. We do not believe our future operations will be materially adversely affected by such requirements or enforcement matters.

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 regulate greenhouse gas emissions. 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*, 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, 2008, the General Partner or its affiliates employed 10 people directly and approximately 138 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 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 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 at reasonable rates;
- 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 items 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 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 assets, 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 lower than in recent periods. For example, the rolling twelve-month average New York Mercantile Exchange, or NYMEX, daily settlement price of natural gas futures contracts per MMBtu was $6.21, $7.96 and $7.23 as of December 31, 2008, 2007 and 2006 respectively. During periods of natural gas price 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, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers' capital budgets, the ability of producers to borrow funds and access capital markets at reasonable rates, the ability of producers to obtain necessary drilling and other governmental permits, 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. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, or declines due to reductions in drilling activity or competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows.

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 or related downstream operations;
- the level of domestic and offshore production;
- a general downturn in economic conditions, including demand for NGLs;
- the availability of imported natural gas, NGLs and crude oil and the demand in the U.S. and globally for these commodities;
- 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 percent-of-proceeds arrangements. Under percent-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 significant 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 through 2013 with derivative instruments.

Our derivative activities and the application of fair value measurements 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 significant 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 5-year credit agreement that matures in June 2012, or the 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 record all of our derivative financial instruments at fair value on our balance sheets primarily using information readily observable within the marketplace. In situations where market observable information is not available, we may use a variety of data points that are market observable, or in certain instances, develop our own expectation of fair value. We will continue to use market observable information as the basis for our fair value calculations, however, there is no assurance that such information will continue to be available in the future. In such instances we may be required to exercise a higher level of judgment in developing our own expectation of fair value, which may be significantly different from the historical fair values, and may increase the volatility of our earnings.

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. 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 or is unable to 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.

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 are 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 30% of the natural gas supplied in our Natural Gas Services segment during the year ended December 31, 2008. 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, two of which are affiliated entities, represented approximately 82% of our propane supplied during the year ended December 31, 2008. In the event that we are unable to purchase propane from our significant suppliers or replace terminated or expired supply contracts, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would affect 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 operations 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 liabilities associated with acquired businesses or assets;
- integrate 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, in August 2007 we acquired certain subsidiaries of MEG that hold our Douglas and Collbran assets from DCP Midstream, LLC and in October 2008, we acquired the Michigan assets. 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 significant liabilities 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 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, as well as reducing the amount of NGL extraction, 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 and impact 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 or 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 are currently 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 rate case 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. In addition, it is possible 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 Texas Railroad Commission, or TRRC.

We currently estimate that we will incur costs of approximately $2.0 million between 2009 and 2013 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 substantial.

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 and economic 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 additions to our existing gathering, transportation and propane terminal assets may require us to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas, natural gas liquids, or propane. If such third party facilities are not constructed or operational at the time that the addition to our facilities is completed, we may experience adverse effects on our results of operations and financial condition. 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 substantial 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.

Recent turmoil in the capital markets may adversely impact our liquidity.

The capital markets have recently experienced volatility, uncertainty and interventions by various governments around the globe. This turmoil in the global capital markets has caused significant financial uncertainty. Our access to funds under the Credit Agreement is dependent on the ability of the lenders that are party to the Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Lehman Brothers Commercial Bank, or Lehman Brothers, a lender to the Credit Agreement, has failed to fund under that agreement since its bankruptcy. Accordingly, the capacity under our Credit Agreement is approximately $824.6 million, excluding Lehman Brothers' unfunded commitment. If additional lenders under the Credit Agreement were to fail to fund their share of the Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the Credit Agreement's financial covenant requirements.

A significant downturn in the economy could adversely affect our results of operations, financial position or cash flows. In the event that our results were negatively impacted, we could require additional funds for working capital purposes. The recent turmoil in the capital markets has resulted in significantly higher costs of public debt and equity funds and reduced funding capabilities generally. Further deterioration in the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

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

Our Credit Agreement has capacity of approximately $824.6 million, assuming no capacity related to Lehman Brothers' unfunded commitment, matures on June 21, 2012, and consists of a $764.6 million revolving credit facility and a $60.0 million term loan facility for working capital and other general corporate purposes. As of December 31, 2008, the outstanding balance on the revolving credit facility was $596.5 million and the outstanding balance on the term loan facility was $60.0 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;
- 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, 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.

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 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. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time 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. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest 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, 2008, our general partner and its affiliates owned approximately 30% of our aggregate outstanding 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;
- 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 issuances by 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, and on February 17, 2009, we satisfied the financial tests contained in our partnership agreement for the early conversion of the remaining 3,571,429 outstanding subordinated units held by DCP Midstream, LLC into common units. After the conversion, DCP Midstream, LLC holds 8,246,451 common units.

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 and a Michigan business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. 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 Schedule K-1's) 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, Michigan, 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 February 23, 2009, we owned and operated processing plants and gathering systems located in Arkansas, Colorado, Louisiana, Michigan, 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 was idled in 2007 to consolidate our operations, 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 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 — On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved, in accordance with accounting principles generally accepted in the United States of America, a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008. This reserve changes our financial results as reported in our earnings release dated February 25, 2009, which date preceded the jury verdict.

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 2008.

PART II

Item 5. *Market for Registrant's Common Equity, and 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 2008 and 2007.

Quarter Ended	High	Low	Distribution Per Common Unit	Distribution Per Subordinated Unit
December 31, 2008	$ 16.94	$ 5.75	$ 0.600	$ 0.600
September 30, 2008	$ 30.21	$ 16.92	$ 0.600	$ 0.600
June 30, 2008	$ 31.51	$ 28.98	$ 0.600	$ 0.600
March 31, 2008	$ 43.51	$ 27.37	$ 0.590	$ 0.590
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

As of February 23, 2009, there were approximately 47 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.

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 held 3,571,429 subordinated units. On February 17, 2009, we satisfied the financial tests contained in our partnership agreement for the early conversion of the remaining 3,571,429 outstanding subordinated units held by DCP Midstream, LLC into common units on a one for one basis.

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.

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.

In March 2008, we issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

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 $0.60 per unit, or $2.40 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 current general partner interest. The general partner has not participated in certain issuances of common units. Therefore, the general partner’s 2% interest has been diluted to approximately 1% as of December 31, 2008. 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.

The incentive distribution rights held by our general partner entitle it to receive an increasing share of Available Cash as pre-defined distribution targets have been achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. Our general partner's incentive distribution rights were not reduced as a result of our March 2008 common limited partner unit offering, 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 in Note 12 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

On January 27, 2009, the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.60 per unit, which was paid on February 13, 2009, to unitholders of record on February 6, 2009.

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, (Millions, except per unit data)				
	2008(a)	2007(a)	2006	2005	2004
Statements of Operations Data:					
Total operating revenues(b)	$ 1,285.8	$ 873.3	$ 795.8	$ 1,144.3	$ 834.0
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	1,061.2	826.7	700.4	1,047.3	760.6
Operating and maintenance expense	43.0	32.1	23.7	22.4	19.8
Depreciation and amortization expense	36.5	24.4	12.8	12.7	14.7
General and administrative expense	24.0	24.1	21.0	14.2	8.7
Other	(1.5)	—	—	—	—
Total operating costs and expenses	1,163.2	907.3	757.9	1,096.6	803.8
Operating income (loss)	122.6	(34.0)	37.9	47.7	30.2
Interest income	5.6	5.3	6.3	0.5	—
Interest expense	(32.8)	(25.8)	(11.5)	(0.8)	—
Earnings from equity method investments(c)	34.3	39.3	29.2	25.7	17.6
Impairment of equity method investment(d)	—	—	—	—	(4.4)
Non-controlling interest in income	(3.9)	(0.5)	—	—	—
Income tax expense(e)	(0.1)	(0.1)	—	(3.3)	(2.5)
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9	$ 69.8	$ 40.9
Less:					
Net income attributable to predecessor operations(f)	—	(3.6)	(26.6)	(65.1)	(40.9)
General partner interest in net income	(11.9)	(2.2)	(0.7)	(0.1)	—
Net income (loss) allocable to limited partners	$ 113.8	$ (21.6)	$ 34.6	$ 4.6	$ —
Net income (loss) per limited partner unit-basic and diluted	$ 3.25	$ (1.05)	$ 1.90	$ 0.20	$ —

	Year Ended December 31,				
	2008(a)	2007(a)	2006	2005	2004
	(Millions, except per unit data)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 629.3	$ 500.7	$ 194.7	$ 178.7	$ 179.3
Total assets	$ 1,180.0	$ 1,120.7	$ 665.9	$ 680.1	$ 472.5
Accounts payable	$ 78.4	$ 165.8	$ 117.3	$ 138.3	$ 63.5
Long-term debt	$ 656.5	$ 630.0	$ 268.0	$ 210.1	$ —
Partners' equity	$ 329.1	$ 168.4	$ 267.7	$ 320.7	$ 400.5
Other Information:					
Cash distributions declared per unit	$ 2.390	$ 2.115	$ 1.565	$ 0.095	N/A
Cash distributions paid per unit	$ 2.360	$ 1.975	$ 1.230	N/A	N/A

(a) Includes the effect of the acquisition of the Southern Oklahoma system in May 2007, certain subsidiaries of Momentum Energy Group, Inc. in August 2007 and Michigan Pipeline & Processing, LLC in October 2008.

(b) Includes the effect of the acquisition of the Swap entered into by DCP Midstream, LLC in March 2007. The Swap was 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 for all periods presented, as well our proportionate share of the 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) In 2004, we recorded our proportionate share of an impairment charge on Black Lake totaling $4.4 million.

(e) Income tax expense for 2004 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 2008 and 2007 represents a margin-based franchise tax in Texas, or the Texas margin tax and a Michigan business tax. See Note 15 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 limited liability company interest in East Texas, our limited liability company interest in Discovery, and the Swap, acquired in July 2007 from DCP Midstream, LLC; (4) our Colorado and Wyoming systems, acquired in August 2007 from DCP Midstream, LLC, which were acquired by DCP Midstream, LLC from Momentum Energy Group, Inc., or MEG, in August 2007 (referred to as the MEG acquisition); and (5) our Michigan systems, acquired in October 2008 from Michigan Pipeline & Processing, LLC (referred to as the MPP acquisition);
- our Wholesale Propane Logistics segment, which consists of six owned rail terminals, one of which was idled in 2007 to consolidate our operations, 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 Seabreeze and Wilbreeze NGL transportation pipelines, and a non-operated equity interest in the Black Lake interstate NGL pipeline.

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

On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved in accordance with accounting principles generally accepted in the United States of America, or GAAP, a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008. This reserve changes our financial results as reported in our earnings release dated February 25, 2009, which date preceded the jury verdict.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to us in exchange for 3.5 million Class D units, providing us with a 50.1% interest in East Texas following the expected closing of the transaction in April 2009. This closing date is subject to extension for up to 45 days to allow for repairs or replacement to our reasonable satisfaction any assets destroyed or damaged by certain casualty losses and time to enable the plant to process all available inlet volumes as defined in the Contribution Agreement. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC has agreed to provide a fixed-price NGL derivative by NGL component for the period of April 2009 to March 2010 for the acquired interest. Subsequent to this transaction, we will consolidate East Texas in our consolidated financial statements.

On February 11, 2009, we announced, along with DCP Midstream, LLC, that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

On February 17, 2009, the remaining 3,571,429 DCP Partners subordinated units were converted to common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners' partnership agreement.

In February 2009, we entered into interest rate swap agreements to convert $275.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps commence in December 2010 and expire in June 2012. In November 2008, we entered into interest rate swap agreements to convert $150.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps expire in December 2010.

As a result of hurricanes during the third quarter of 2008, certain of our owned and operated facilities were fully or partially curtailed pending resumption of electric power and operations at downstream third party NGL facilities, in some cases. All of our operated assets have since been returned to service. There has been some temporary impact to demand as third party NGL facilities are returned to service. The net income impact of hurricane-related damages and lost margins due to curtailed operations for the third and fourth quarters of 2008 was approximately $14.7 million, including losses from our equity method investment in Discovery.

In January 2009, repairs were completed on Discovery's 30-inch mainline, restoring approximately 85% of volumes and margins to the system. With the completion of the 18-inch lateral repairs, the remaining volumes are expected to be restored in early March. We did not receive a fourth quarter distribution from Discovery, which would have been paid during January 2009. We anticipate distributions to resume for the first quarter of 2009, which will be paid in April 2009. Discovery's offshore gathering system had been damaged by hurricane Ike in September 2008 when an 18-inch lateral was severed from its connection to the 30-inch mainline in 250 feet of water.

On January 27, 2009, the board of directors of the general partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

In January 2009, Don Baldridge was appointed to Vice President, Business Development. Previously, Mr. Baldridge was Vice President, Corporate Development for DCP Midstream, LLC. Mr. Baldridge is replacing Greg K. Smith, who was appointed Vice President, Gas Supply for DCP Midstream, LLC.

In early January 2009, the second phase of our Wyoming pipeline and systems enhancement project was completed, returning over 80% of the system volumes to service. The final phase is on target for completion in March.

In December 2008, we made contributions of $1.9 million to Discovery, $1.6 million of which was to fund hurricane damages and $0.3 million was to fund capital expansion. In December 2008 we received a distribution of $2.5 million from East Texas and paid a contribution of $2.6 million to East Texas to fund capital expansion.

In October 2008, due to executive management rotational changes at ConocoPhillips, Willie C.W. Chiang and Sigmund L. Cornelius resigned as directors of the board of directors of our general partner, and John E.

Lowe and Gregory J. Goff were appointed as the ConocoPhillips representatives to the board of directors. Mr. Lowe currently serves as assistant to the Chief Executive Officer of ConocoPhillips, an affiliate of our general partner and Mr. Goff currently serves as Senior Vice President, Commercial of ConocoPhillips. Mr. Goff was also appointed to DCP Partners' compensation committee in December 2008.

In October 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million, subject to additional customary purchase price adjustments, plus up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay us up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied, and as a result, the amount has been reduced to $0.8 million per year as of February 23, 2009. We initially held a $25.0 million letter of credit to secure the seller's performance under this agreement and to secure the seller's indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount has been reduced to $22.5 million as of February 23, 2009. The fees under the omnibus agreement with DCP Midstream, LLC increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

Factors That Significantly Affect Our Results

Capital Markets

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. The uncertainty in the capital markets may impact our business in multiple ways, including limiting our producers' ability to finance their drilling programs and limiting our ability to grow our operations through acquisitions or organic growth projects. These events may impact our counterparties' ability to perform under their credit or commercial obligations. While we did not experience significant collection issues during 2008, we continue to monitor the payment patterns of our customers. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines. To date, our counterparties to our existing derivative instruments have fully performed under their commitments. Due to the bankruptcy of Lehman Brothers Commercial Bank, or Lehman Brothers, a lender to our Credit Agreement, the availability of borrowings under this facility has been reduced by approximately $25.4 million. Accordingly, the capacity under our Credit Agreement is approximately $824.6 million, excluding Lehman Brothers' unfunded commitment.

Impact of Severe Weather

The economic impact of severe weather may negatively affect the nation's short-term energy supply and demand, and may result in increased commodity prices. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Severe weather may also impact the supply and demand in our wholesale propane business.

Other Factors

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) increases and decreases in the volume of natural gas that we gather and transport through our systems, which we refer to as throughput, (2) prices of commodities such as NGLs, crude oil and natural gas, (3) the operating efficiency of our processing facilities, and (4) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints. Throughput and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Throughput and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Natural Gas Services segment results of operations 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, impacting our expansion in regions where certain types of contracts are more common and other market factors.

Additionally, our results of operations for our Natural Gas Services segment are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. 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 in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue 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. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary.

While pricing impacts the Natural Gas Services segment, we have mitigated a significant portion of the anticipated commodity price risk associated with the equity volumes from our gathering and processing operations, for both our consolidated entities and our proportionate share of exposure from our equity method investments, through 2013 with fixed price natural gas and crude oil swaps. We mark these derivative instruments to market through current period earnings based upon their fair value. While the swaps may 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 changes in the fair value of these derivatives. We primarily use crude oil swaps to mitigate our NGL and condensate 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 and we have financial risk exposure to the extent our actual equity volumes differ from our projections. For additional information regarding our derivative activities, please read "— Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk — Commodity Cash Flow Protection Activities."

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall below demand levels.

Wholesale Propane Logistics Segment

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. We may mitigate a portion of the anticipated commodity price risk associated with fixed price propane sales by entering into either offsetting physical purchase agreements or financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to these fixed price sales agreements. There may be an impact on sales volumes from weather conditions in the midwest and northeastern areas of the United States. Our annual sales volumes of propane may decline when these areas experience periods of milder weather in the winter months. Volumes may also be impacted by conservation and reduced demand in the current recessionary environment.

NGL Logistics Segment

Our results of operations for our NGL Logistics segment are impacted by the throughput volumes of the NGLs we transport on our NGL pipelines, as we transport NGLs exclusively on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low commodity prices for ethane. During the fourth quarter of 2008, we did experience reduced throughput due to ethane rejection at certain plants. Factors that impact the supply and demand of NGLs, as described above in our Natural Gas Services segment, may also impact the throughput for our NGL Logistics segment.

Other

The above factors, including further sustained deterioration in commodity prices, volumes or other market declines, including a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

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.

Commodity Prices — In the fourth quarter of 2008, natural gas, NGL and crude oil prices dropped significantly compared to prices in 2007 and the first three quarters of 2008. We are continuing to experience relatively lower commodity prices in 2009. Commodity prices are impacted by demand, which has been negatively impacted by the current recessionary environment.

Natural Gas Supply and Outlook — In the near term, softening of natural gas prices, reduced demand for natural gas and NGLs, potential reduction in available capital, and the recent downturn in the economy have had a moderating effect on levels of drilling activity. The impact of these factors will vary across our broad geographic locations. Generally, we expect a decrease in drilling levels in 2009. The number of active oil and gas rigs drilling in the United States was 364 and 1,347, respectively, at December 31, 2008, compared to 325 and 1,452, respectively, at December 31, 2007. Our long-term view is that natural gas prices will return to a level that would support the relatively higher levels of natural gas-related drilling experienced in recent years in the United States, as producers seek to increase their level of natural gas production. We believe that in the long-term 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 natural gas in the United States.

Additionally, the capacity on certain downstream NGL and natural gas infrastructure has tightened recently and can be further constrained seasonally or when there is severe weather. Constrained market outlets may restrict us from operating our facilities optimally.

Processing Margins — Except for our fee-based contracts, 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 significant 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 — The natural gas services business 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. Recently however, we have seen softening in certain costs. In the future, we may again 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.

2009 Outlook

Our focus in 2009 will be on the basics of the business, including operating our assets well, being disciplined with all uses of funds and effectively managing our business risk and daily operations in a very uncertain and volatile business environment.

The restoration of our operations is nearing completion. Repairs to the Discovery system, which was damaged by the hurricanes in fall 2008, were substantially completed in January 2009. Approximately 85% of the volumes and margins have been returned to service, with the remainder expected by early March. The Discovery distribution is paid one quarter in arrears. We do not expect to receive a distribution from Discovery during the first quarter of 2009. We would expect to receive a distribution during the second quarter of 2009, commensurate with the partial restoration in January 2009, and a distribution during the third quarter of 2009, commensurate with the return to full service. The second phase of our Douglas pipeline integrity and system enhancement project has been completed, returning over 80% of the system volumes to service by mid-January 2009. The final phase is on target for completion in March 2009.

We are in the process of returning gas online following the fire caused by a third party pipeline rupture near our Carthage Hub, and expect it to be returned to normal service by the end of March 2009.

We will continue to execute on our two organic growth projects in the Piceance Basin and East Texas. We expect the remaining spending to be approximately $65.0 million in 2009, which will be funded through our existing credit facility.

We expect to close the transaction with DCP Midstream, LLC in April 2009 to acquire an additional 25.1% interest in East Texas. We expect the transaction will be fully financed through the issuance of 3.5 million Class D units issued to DCP Midstream, LLC. The transaction is expected to generate cash flow from operations of approximately $15.0 million over the first twelve month period following the close of the transaction. As a part of the transaction, DCP Midstream, LLC is expected to provide a fixed price NGL derivative by component for the first twelve month period following the close of the transaction.

Cash flow assumptions for our 2009 outlook include a full year impact from our Michigan acquisition, an increase in cash flows during the second half of the year related to our Piceance Basin and East Texas capital projects, and maintenance capital of $10.0 million to $15.0 million, which includes the remaining spending for the Douglas pipeline integrity and system enhancement project. In total, we estimate the impact to cash flow in 2009 as a result of operations disruptions at Discovery and Douglas to be approximately $10.0 million to $12.0 million.

Our cash flows are expected to vary under various commodity price scenarios. However, the combination of our significant fee-based business, our highly hedged position and minimum fees in certain contracts provide downside protection to our cash flows.

Our percentage of fee-based margins is expected to be approximately 56% in 2009. We have hedged approximately 80% of our equity position in natural gas liquids, condensate and natural gas associated with the remainder of our expected margins that are not fee-based.

Based upon our business plan, we expect that our available capacity under our existing credit facility is sufficient to support our operating needs and capital program in 2009.

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 from 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.
- *Percent-of-proceeds* — Under percent-of-proceeds 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 arrangements correlate directly with the price of natural gas and/or NGLs.

In addition to the above contract types, our equity method investments 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 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 natural gas gathered. This arrangement keeps the producer whole to the thermal value of the 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 when that frac spread exceeds the operating costs of our equity method investments. Fluctuations in commodity prices are expected to continue to impact the operating costs of these entities.

We have mitigated a significant portion of our anticipated natural gas, NGL and condensate commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with fixed price 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, Michigan, 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 30% of the 499 MMcf/d of natural gas supplied to this system in 2008. 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 directly received or 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 may 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, two of which are affiliated entities, represented approximately 82% of our propane supplied in 2008. 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 generally 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 generally significantly greater than their purchase of propane from us in the summer. We believe these factors generally allow us to maintain our generally 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 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 typically 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. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may use financial derivatives to manage the value of our propane inventories.

NGL Logistics Segment

Our pipelines provide transportation services for 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 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 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, segment gross margin and adjusted segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) EBITDA and adjusted EBITDA; and (5) distributable cash flow. Gross margin, segment gross margin, adjusted segment gross margin, EBITDA, adjusted EBITDA and distributable cash flow measurements are not GAAP financial measures. We provide reconciliations of certain non-GAAP measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP 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 important factors 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 our pipelines, and pursue opportunities to connect new supply to these pipelines.

Gross Margin, Segment Gross Margin and Adjusted Segment 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. We define adjusted segment gross margin as segment gross margin plus non-cash derivative losses, less non-cash derivative gains for that segment. Gross margin, segment gross margin and adjusted segment gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, gross margin, segment gross margin and adjusted segment gross margin should not be considered an alternative to, or more meaningful than, net income or loss, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

Our gross margin, segment gross margin and adjusted segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The following table sets forth our reconciliation of certain non-GAAP measures:

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2008	2007	2006
		(Millions)	
Reconciliation of net income (loss) to gross margin:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Interest expense	32.8	25.8	11.5
Income tax expense	0.1	0.1	—
Operating and maintenance expense	43.0	32.1	23.7
Depreciation and amortization expense	36.5	24.4	12.8
General and administrative expense	24.0	24.1	21.0
Other	(1.5)	—	—
Non-controlling interest in income	3.9	0.5	—
Interest income	(5.6)	(5.3)	(6.3)
Earnings from equity method investments	(34.3)	(39.3)	(29.2)
Gross margin	$ 224.6	$ 46.6	$ 95.4
Reconciliation of segment net income to segment gross margin:			
Natural Gas Services segment:			
Segment net income	$ 170.2	$ 11.6	$ 79.6
Depreciation and amortization expense	33.8	21.9	11.1
Operating and maintenance expense	32.1	20.9	13.5
Non-controlling interest in income	3.9	0.5	—
Earnings from equity method investments	(33.5)	(38.7)	(28.9)
Segment gross margin	$ 206.5	$ 16.2	$ 75.3
Non-cash commodity derivative mark-to-market(a)	$ 99.2	$ (78.3)	$ 0.1
Wholesale Propane Logistics segment:			
Segment net income	$ 1.3	$ 14.0	$ 6.6
Depreciation and amortization expense	1.3	1.1	0.8
Operating and maintenance expense	9.9	10.4	8.6
Other	(1.5)	—	—
Segment gross margin	$ 11.0	$ 25.5	$ 16.0
Non-cash commodity derivative mark-to-market(a)	$ 2.4	$ (2.8)	$ —
NGL Logistics segment:			
Segment net income	$ 5.5	$ 3.3	$ 1.9
Depreciation and amortization expense	1.4	1.4	0.9
Operating and maintenance expense	1.0	0.8	1.6
Earnings from equity method investments	(0.8)	(0.6)	(0.3)
Segment gross margin	$ 7.1	$ 4.9	$ 4.1

(a) Non-cash commodity derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

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.

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. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition of MPP. 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. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $43.0 million at December 31, 2008, to certain counterparties to our commodity derivative instruments.

Our total general and administrative expense was comprised of the following:

	Year Ended December 31,		
	2008	2007	2006
Affiliate:			
Omnibus Agreement:			
Annual fee	$ 5.1	$ 5.0	$ 4.8
Wholesale propane logistics business	2.0	2.0	0.3
Southern Oklahoma	0.2	0.1	—
Discovery	0.2	0.1	—
Additional services	0.6	0.2	—
Momentum Energy Group, Inc.	1.6	0.5	—
Michigan Pipeline & Processing, LLC	0.1	—	—
Total Omnibus Agreement	9.8	7.9	5.1
Other — DCP Midstream, LLC	1.8	2.1	3.0
Total affiliate	11.6	10.0	8.1
Other	12.4	14.1	12.9
Total	$ 24.0	$ 24.1	$ 21.0

Following is a summary of the fees we anticipate incurring in 2009 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
Momentum Energy Group, Inc.	August 2007	1.6
Michigan Pipeline & Processing, LLC	October 2008	0.4
Total		$ 10.1

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 for certain 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 certain credit ratings 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 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.

All of the fees under the Omnibus Agreement will be adjusted annually by the percentage change 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, Adjusted EBITDA and Distributable Cash Flow — We define EBITDA as net income or loss less interest income, plus interest expense, income tax expense and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus non-cash commodity derivative losses, less non-cash commodity derivative gains. EBITDA and adjusted EBITDA are used as supplemental liquidity and performance measures 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;
- 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.

Our EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of another company because other entities may not calculate these measures in the same manner. As discussed in the Liquidity and Capital Resources section below, our credit facility also defines EBITDA, which is used in evaluating our compliance with our financial covenants.

EBITDA and adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, 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. The following table sets forth reconciliations of EBITDA from its most directly comparable financial measures calculated in accordance with GAAP:

Reconciliation of Non-GAAP Measures	Year Ended December 31, 2008	2007	2006
		(Millions)	
Reconciliation of net income (loss) to EBITDA:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Interest income	(5.6)	(5.3)	(6.3)
Interest expense	32.8	25.8	11.5
Income tax expense	0.1	0.1	—
Depreciation and amortization expense	36.5	24.4	12.8
EBITDA	$ 189.5	$ 29.2	$ 79.9
Reconciliation of net cash provided by operating activities to EBITDA:			
Net cash provided by operating activities	$ 101.5	$ 65.4	$ 94.8
Interest income	(5.6)	(5.3)	(6.3)
Interest expense	32.8	25.8	11.5
Earnings from equity method investments, net of distributions	(25.6)	0.4	3.3
Income tax expense	0.1	0.1	—
Net changes in operating assets and liabilities	89.8	(56.9)	(25.8)
Other, net	(3.5)	(0.3)	2.4
EBITDA	$ 189.5	$ 29.2	$ 79.9

We define distributable cash flow as net cash provided by or used in operating activities, less maintenance capital expenditures, net of reimbursable projects, plus or minus adjustments for non-cash mark-to-market of derivative instruments, proceeds from divestiture of assets, non-controlling interest on depreciation, 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.

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, 2008 weighted-average cost, our net income would be affected by approximately $2.1 million.
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.	We completed our impairment testing of goodwill using the methodology described herein, and determined there was no impairment. We have not recorded goodwill impairment during the year ended December 31, 2008. The carrying value of goodwill as of December 31, 2008 was $88.8 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 sum of undiscounted 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, 2008. 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, 2008 was $677.0 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, 2008. 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, 2008 was $175.4 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, 2008 would have affected net income by approximately $2.0 million for the year ended December 31, 2008.
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.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
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 credit adjusted 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, 2008, 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, 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31, 2008(a)	2007(a)	2006	Variance 2008 vs. 2007 Increase (Decrease)	Percent	Variance 2007 vs. 2006 Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues:							
Natural Gas Services(b)	$ 791.5	$ 404.1	$ 415.3	$ 387.4	96%	$ (11.2)	(3)%
Wholesale Propane Logistics	483.0	459.6	375.2	23.4	5%	84.4	23%
NGL Logistics	11.3	9.6	5.3	1.7	18%	4.3	81%
Total operating revenues	1,285.8	873.3	795.8	412.5	47%	77.5	10%
Gross margin(c):							
Natural Gas Services	206.5	16.2	75.3	190.3	1,175%	(59.1)	(78)%
Wholesale Propane Logistics	11.0	25.5	16.0	(14.5)	(57)%	9.5	59%
NGL Logistics	7.1	4.9	4.1	2.2	45%	0.8	20%
Total gross margin	224.6	46.6	95.4	178.0	382%	(48.8)	(51)%
Operating and maintenance expense	(43.0)	(32.1)	(23.7)	10.9	34%	8.4	35%
General and administrative expense	(24.0)	(24.1)	(21.0)	(0.1)	—%	3.1	15%
Other	1.5	—	—	1.5	*	—	—%
Earnings from equity method investments(d)	34.3	39.3	29.2	(5.0)	(13)%	10.1	35%
Non-controlling interest in income	(3.9)	(0.5)	—	3.4	680%	0.5	100
EBITDA(e)	189.5	29.2	79.9	160.3	549%	(50.7)	(64)%
Depreciation and amortization expense	(36.5)	(24.4)	(12.8)	12.1	50%	11.6	91%
Interest income	5.6	5.3	6.3	0.3	6%	(1.0)	16%
Interest expense	(32.8)	(25.8)	(11.5)	7.0	27%	14.3	*
Income tax expense	(0.1)	(0.1)	—	—	—%	0.1	100%
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9	$ 141.5	*	$ (77.7)	*
Operating data:							
Natural gas throughput (MMcf/d)(d)	838	756	666	82	11%	90	14%
NGL gross production (Bbls/d)(d)	20,659	22,122	19,485	(1,463)	(7)%	2,637	14%
Propane sales volume (Bbls/d)	21,053	22,798	21,259	(1,745)	(8)%	1,539	7%
NGL pipelines throughput (Bbls/d)(d)	31,407	28,961	25,040	2,446	8%	3,921	16%

* Percentage change is not meaningful.

(a) Includes the results from the Michigan Pipeline & Processing, LLC, or MPP, Momentum Energy Group, Inc, or MEG, and Southern Oklahoma acquisitions, from their respective acquisition dates of October 2008, August 2007 and May 2007.

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

(c) Gross margin consists of total operating revenues, including commodity derivative activity, 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.

(d) Includes our proportionate share of the throughput volumes and earnings of Black Lake, East Texas and Discovery for all periods presented. 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.

(e) EBITDA consists of net income or loss 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, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

- $213.7 million increase primarily attributable to increased commodity prices as well as higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes, for our Natural Gas Services segment;
- $156.8 million increase related to commodity derivative activity, resulting from the following:
  - we had a gain of $72.3 million in 2008 and a loss of $87.6 million in 2007, resulting in an increase of $159.9 million, which is included in gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $184.1 million due to forward prices of commodities generally being lower at the end of the year 2008 compared to 2007. Offsetting this increase in gain was an increase in realized cash settlement losses of $24.2 million due to average prices of commodities generally being higher for the year ended December 31, 2008 compared to 2007; and
  - we had a $3.1 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $22.1 million increase in transportation processing and other revenue, primarily attributable to the MEG and MPP acquisitions in our Natural Gas Services segment;
- $19.0 million increase attributable to higher propane prices offset by decreased propane sales volumes as a result of lower demand for our Wholesale Propane Logistics segment; and
- $0.9 million increase due to increased throughput volumes, transportation, processing and other revenue, and increases related to settlement of pipeline imbalances in our NGL logistics segment.

Gross Margin — Gross margin increased in 2008 compared to 2007, primarily due to the following:

- $190.3 million increase for our Natural Gas Services segment primarily due to increases related to commodity derivative activity, an increase in natural gas, NGL and condensate production, mainly as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes; and
- $2.2 million increase for our NGL Logistics segment primarily attributable to increases related to settlement of pipeline imbalances and increased throughput volumes; partially offset by
- $14.5 million decrease for our Wholesale Propane Logistics segment as a result of increased non-cash lower of cost or market inventory adjustments due to a decline in propane prices in the second half of 2008. We estimate that approximately half of the 2008 write downs were recovered through the sale of inventory in 2008. We also had lower per unit margins and propane sales volumes, partially offset by commodity derivative activity.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions in our Natural Gas Services segment, partially offset by decreased property taxes in our Wholesale Propane Logistics segment.

General and Administrative Expense — General and administrative expense decreased in 2008 compared to 2007, primarily due to acquisition-related costs incurred in 2007 and decreased compensation and benefits in 2008, partially offset by increased legal expenses in 2008.

Earnings from Equity Method Investments — Earnings from equity method investments decreased in 2008 compared to 2007, primarily due to decreased equity earnings of $6.7 million from Discovery due primarily to hurricanes, as discussed in the Natural Gas Services Segment section below, partially offset by increased equity earnings of $1.5 million from East Texas and $0.2 million from Black Lake.

Non-Controlling Interest in Income — Non-controlling interest in income reduced income by $3.9 million and $0.5 million in 2008 and 2007, respectively, 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 and in 2008 also includes the non-controlling interest holders' portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of acquisitions.

Interest Expense — Interest expense increased in 2008 compared to 2007, primarily as a result of financing acquisitions, partially offset by lower average interest rates.

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 processing and other 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 which is included in sales of natural gas, NGLs and condensate, and a decrease of $87.7 million 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 processing and other 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.

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, our Colorado and Wyoming systems, acquired in August 2007 and our Michigan systems, acquired in October 2008.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008(a)	2007(a)	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of natural gas, NGLs and condensate	$ 668.8	$ 458.2	$ 391.8	$ 210.6	46%	$ 66.4	17%
Transportation, processing and other	50.2	29.4	23.5	20.8	71%	5.9	25%
Gains (losses) from commodity derivative activity(b)	72.5	(83.5)	—	156.0	*	(83.5)	*
Total operating revenues	791.5	404.1	415.3	387.4	96%	(11.2)	(3)%
Purchases of natural gas and NGLs	585.0	387.9	340.0	197.1	51%	47.9	14%
Segment gross margin(c)	206.5	16.2	75.3	190.3	1,175%	(59.1)	(79)%
Operating and maintenance expense	(32.1)	(20.9)	(13.5)	11.2	54%	7.4	55%
Depreciation and amortization expense	(33.8)	(21.9)	(11.1)	11.9	54%	10.8	97%
Earnings from equity method investments(d)	33.5	38.7	28.9	(5.2)	(13)%	9.8	34%
Non-controlling interest in income	(3.9)	(0.5)	—	3.4	680%	0.5	100%
Segment net income	$ 170.2	$ 11.6	$ 79.6	$ 158.6	1,367%	$ (68.0)	(85)%
Operating data:							
Natural gas throughput (MMcf/d)(d)	838	756	666	82	11%	90	14%
NGL gross production (Bbls/d)	20,659	22,122	19,485	(1,463)	(7)%	2,637	14%

* Percentage change is not meaningful.

(a) Includes the results from the MEG, MPP and Southern Oklahoma acquisitions, from their respective acquisition dates of October 2008, August 2007 and May 2007.

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

(c) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas and NGLs. Please read “How We Evaluate Our Operations” above.

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

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

- $152.9 million increase related to commodity derivative activity, resulting from the following:
  - we had a gain of $72.5 million in 2008 and a loss of $83.5 million in 2007, resulting in an increase of $156.0 million, which is included gains (losses) from commodity derivative activity. This increase includes an increase in unrealized gains of $178.8 million due to forward prices of commodities generally being lower at the end of the year 2008 compared to 2007. Offsetting this increase in gain was an increase in realized cash settlement losses of $22.8 million due to average prices of commodities generally being higher for the year ended December 31, 2008 compared to 2007; and
  - we had a $3.1 million increase in unrealized loss, which is included in sales of natural gas, NGLs and condensate;
- $150.3 million increase attributable to increased commodity prices;
- $63.4 million increase attributable to higher natural gas, NGL and condensate sales volumes, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes; and
- $20.8 million increase in transportation, processing and other revenue as a result of the MEG and MPP acquisitions.

Purchases of Natural Gas and NGLs — Purchases of natural gas and NGLs increased in 2008 compared to 2007, primarily due to increased natural gas purchase volumes primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions, and higher costs of natural gas supply, driven by higher commodity prices.

Segment Gross Margin — Segment gross margin increased in 2008 compared to 2007, primarily as a result of the following:

- $152.9 million increase related to commodity derivative activity, as discussed in the Operating Revenues section above;
- $24.1 million increase primarily attributable to an increase in natural gas, NGL and condensate production as a result of the MEG, MPP and Southern Oklahoma acquisitions, partially offset by decreased volumes due to the impact of hurricanes;
- $9.0 million increase primarily attributable to changes in contract mix; and
- $4.3 million increase due to higher commodity prices.

Operating and Maintenance Expense — Operating and maintenance expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions.

Depreciation and Amortization Expense — Depreciation and amortization expense increased in 2008 compared to 2007, primarily as a result of the MEG, MPP and Southern Oklahoma acquisitions.

Earnings from Equity Method Investments — Earnings from equity method investments decreased in 2008 compared to 2007, primarily due to decreased equity earnings of $6.7 million from Discovery, partially offset by increased equity earnings of $1.5 million from East Texas. Decreased 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 Discovery were the result of a decrease in Discovery's net income of $13.7 million due primarily to $32.5 million resulting from hurricanes Ike and Gustav, partially offset by $10.4 million higher product margins, $4.6 million lower depreciation and accretion expense and a 2008 reserve reversal of $3.5 million related to a recently approved Federal Energy Regulatory Commission rate case settlement.

- Increased equity earnings from East Texas were the result of an increase in East Texas's net income of $6.0 million due primarily to a $14.9 million increase as a result of higher commodity prices, a $9.0 million increase due to increased fee-based revenue, and decreased general and administrative expenses of $2.9 million, partially offset by a $12.9 million decrease due to decreased NGL production, partially due to the effects of hurricanes and other severe weather and an increase in operating and maintenance expenses of $7.3 million.

Non-Controlling Interest in Income — Non-controlling interest in income reduced income by $3.9 million and $0.5 million in 2008 and 2007, respectively, 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 and in 2008 also includes the non-controlling interest holders' portion of the net income of Jackson Pipeline Company, acquired in the MPP acquisition.

Natural gas transported and/or processed increased in 2008 compared to 2007, due primarily to increased volumes from the MEG, MPP and Southern Oklahoma acquisitions and increased volumes from East Texas, partially offset by decreased volumes from Pelico and Discovery. NGL production decreased in 2008 compared to 2007, due primarily to decreased NGL production at Discovery as a result of the hurricanes.

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 which is included in sales of natural gas, NGLs and condensate, and a decrease of $83.5 million 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, processing and other 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.

Results of Operations — Wholesale Propane Logistics Segment

This segment includes our propane transportation facilities, which includes six owned rail terminals, one of which was idled in 2007 to consolidate our operations, one leased marine terminal, one pipeline terminal and access to several open-access propane pipeline terminals.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2007 vs. 2006	
	2008	2007	2006	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 482.1	$ 463.1	$ 375.0	$ 19.0	4%	$ 88.1	24%
Transportation, processing and other	1.1	0.6	0.1	0.5	83%	0.5	*
(Losses) gains from commodity derivative activity	(0.2)	(4.1)	0.1	(3.9)	(95)%	(4.2)	*
Total operating revenues	483.0	459.6	375.2	23.4	5%	84.4	23%
Purchases of propane	472.0	434.1	359.2	37.9	9%	74.9	21%
Segment gross margin(a)	11.0	25.5	16.0	(14.5)	(57)%	9.5	59%
Operating and maintenance expense	(9.9)	(10.4)	(8.6)	(0.5)	(5)%	1.8	21%
Depreciation and amortization expense	(1.3)	(1.1)	(0.8)	0.2	18%	0.3	38%
Other	1.5	—	—	1.5	*	—	—%
Segment net income	$ 1.3	$ 14.0	$ 6.6	$ (12.7)	(91)%	$ 7.4	*
Operating Data:							
Propane sales volume (Bbls/d)	21,053	22,798	21,259	(1,745)	(8)%	1,539	7%

* Percentage change is not meaningful.

(a) Segment gross margin consists of total operating revenues, including commodity derivative activity, less purchases of propane. Please read “How We Evaluate Our Operations” above.

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to the following:

- $54.1 million increase attributable to higher propane prices;
- $3.9 million increase related to commodity derivative activity, which represents increased unrealized gains of $5.3 million, partially offset by increased realized cash settlement losses of $1.4 million; and
- $0.5 million increase attributable to other fee revenue; partially offset by
- $35.1 million decrease attributable to decreased propane sales volumes as a result of lower demand.

Purchases of Propane — Purchases of propane increased in 2008 compared to 2007, primarily due to increased prices, partially offset by decreased purchased volumes.

Segment Gross Margin — Segment gross margin decreased in 2008 compared to 2007, primarily as a result of increased non-cash lower of cost or market inventory adjustments of $15.1 million due to a decline in propane prices in the second half of 2008. We estimate that approximately half of the 2008 write downs were recovered through the sale of inventory in 2008. We also had lower per unit margins and lower propane sales volumes, partially offset by commodity derivative activity.

Propane sales volume decreased in 2008 compared to 2007, primarily as a result of lower demand.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2008 compared to 2007, primarily due to decreased property taxes.

Other — Other operating income increased due to a payment received in the second quarter of 2008 from a supplier related to the early termination of its supply agreement.

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, processing and other 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.

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 2008 vs. 2007		Variance 2007 vs. 2006	
	2008	2007	2006	Increase (Decrease)	Percent	(Decrease)	Increase Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of NGLs	$ 5.4	$ 4.5	$ 1.1	$ 0.9	20%	$ 3.4	*
Transportation, processing and other	5.9	5.1	4.2	0.8	16%	0.9	21%
Total operating revenues	11.3	9.6	5.3	1.7	18%	4.3	81%
Purchases of NGLs	4.2	4.7	1.2	(0.5)	(11)%	3.5	*
Segment gross margin(a)	7.1	4.9	4.1	2.2	45%	0.8	20%
Operating and maintenance expense	(1.0)	(0.8)	(1.6)	0.2	25%	(0.8)	(50)%
Depreciation and amortization expense	(1.4)	(1.4)	(0.9)	—	—%	0.5	56%
Earnings from equity method investment(b)	0.8	0.6	0.3	0.2	33%	0.3	100%
Segment net income	$ 5.5	$ 3.3	$ 1.9	$ 2.2	67%	$ 1.4	74%
Operating data:							
NGL pipelines throughput (Bbls/d)(b)	31,407	28,961	25,040	2,446	8%	3,921	16%

* Percentage change is not meaningful.

(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 for all periods presented. Earnings for Black Lake include the amortization of the net difference between the carrying amount of the investment and the underlying equity of the investment.

Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Total Operating Revenues — Total operating revenues increased in 2008 compared to 2007, primarily due to increased throughput volumes, increased transportation, processing and other revenue, and increases related to settlement of pipeline imbalances.

Purchases of NGLs — Purchases of NGLs decreased in 2008 compared to 2007, due to settlement of pipeline imbalances, partially offset by increased throughput volumes.

Segment Gross Margin — Segment gross margin increased in 2008 compared to 2007, primarily due to increases related to settlement of pipeline imbalances and increased throughput volumes.

Overall, our NGL pipelines experienced an increase in throughput volumes in 2008 as compared to 2007, primarily as a result of an increase in processing activity associated with increased drilling due to higher commodity prices.

Earnings from Equity Method Investments — Earnings from equity method investments increased in 2008 compared to 2007, due to increased throughput volumes resulting in higher Black Lake equity earnings.

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, processing and other revenue. Increased volumes and transportation, processing and other 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, processing and other 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.

Liquidity and Capital Resources

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;
- debt offerings;
- guarantees issued by DCP Midstream, LLC, which reduce the amount of collateral we may be required to post with certain counterparties to our commodity derivative instruments; and
- letters of credit.

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, which may, at times, be significant depending on commodity price movements, and which is required to the extent we exceed certain guarantees issued by DCP Midstream, LLC and letters of credit we have posted; 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. In the event these sources are not sufficient, we would reduce our discretionary spending, which may include capital spending.

Beginning in the third quarter of 2008, the capital markets experienced volatility, uncertainty and interventions by various governments around the globe. The effects of these market conditions include significant changes in the valuation of equity securities and overnight and longer-term borrowing rates. The availability of credit through traditional sources of funding such as the commercial paper, bank lending and the private and public placement debt markets also decreased dramatically. In these market conditions, it is uncertain if we would be successful in obtaining timely additional funding from the traditional equity or debt markets if it were needed. Furthermore, the cost of such new funding could substantially exceed the cost of funds previously obtained. Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our business, although deterioration in our operating environment beyond that currently anticipated could limit our borrowing capacity as well as impact our compliance with the Credit Agreement's financial covenant requirements.

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 significant portion of our anticipated commodity price risk associated with the equity volumes from our gathering and processing operations through 2013 with fixed price 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."

Our banking group is comprised of various financial institutions, of which certain institutions have recently merged. We do not expect the aggregate contractual financial commitment of these institutions to us to change during the remaining life of our existing credit agreement as a result of these mergers.

The capacity under our Credit Agreement is approximately $824.6 million, net of Lehman Brothers' unfunded commitment. Our borrowing capacity may be limited by the Credit Agreement's financial covenant requirements. Except in the case of a default, which would make the borrowings under the Credit Agreement fully callable, amounts borrowed under our Credit Agreement will not mature prior to the June 21, 2012 maturity date. As of February 23, 2009, we had approximately $228.0 million of net available borrowings under our Credit Agreement.

Certain of our counterparties are experiencing financial difficulties, which did not have a significant impact on our business in 2008.

The counterparties to each of our commodity 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. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty's assessment of creditworthiness. 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 we may transact multiple commodities with the same counterparty. As of February 23, 2009, DCP Midstream, LLC had issued and outstanding parental guarantees totaling $83.0 million to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with these counterparties. Prior to our initial public offering, DCP Midstream, LLC provided parental guarantees to certain counterparties to our commodity derivative instruments, totaling $43.0 million as of February 23, 2009. In July 2008, DCP Midstream, LLC provided additional parental guarantees to certain counterparties to our commodity derivative instruments, totaling $40.0 million as of February 23, 2009. We pay DCP Midstream, LLC a fee of 0.5% per annum on $40.0 million of these guarantees. The fee on the remaining guarantees is covered under the omnibus agreement with DCP Midstream, LLC. As of February 23, 2009, we had a letter of credit of $10.0 million. These parental guarantees and letter of credit reduce the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility. As of February 23, 2009, we had no cash collateral posted with counterparties. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis. Predetermined collateral thresholds for commodity derivative instruments 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.

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.

As of December 31, 2008, we had $48.0 million in cash and cash equivalents. Of this balance, as of December 31, 2008, $21.2 million was held by Collbran Valley Gas Gathering, or Collbran, our 70% owned joint venture which we consolidate in our financial results. Other than the cash held by Collbran, this cash balance was available for general corporate purposes.

We had working capital of $40.4 million as of December 31, 2008 and a working capital deficit of $1.1 million as of December 31, 2007. 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 **—** Operating, investing and financing activities was as follows:

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Net cash provided by operating activities	$ 101.5	$ 65.4	$ 94.8
Net cash used in investing activities	$ (166.9)	$ (521.7)	$ (93.8)
Net cash provided by financing activities	$ 88.9	$ 434.6	$ 3.0

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 predecessor were handled by DCP Midstream, LLC and were reflected in partners’ equity as intercompany advances from DCP Midstream, LLC. We maintain our own bank accounts, which are managed by DCP Midstream, LLC.

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 $59.9 million, $38.9 million and $25.9 million during the years ended December 31, 2008, 2007 and 2006, respectively. Distributions exceeded earnings by $25.6 million for the year ended December 31, 2008. Earnings exceeded distributions by $0.4 million and $3.3 million for the years ended December 31, 2007 and 2006, respectively.

Net Cash Used in Investing Activities — Net cash used in investing activities during 2008 was primarily used for: (1) acquisition of MPP of $146.4 million; acquisition of the MEG subsidiaries of $10.9 million; (2) capital expenditures of $41.0 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, including the pipeline integrity costs and system upgrades at Douglas and (3) investments in equity method investments of $13.8 million; and (4) acquisition of the MEG subsidiaries of $10.9 million; which were partially offset by (5) net proceeds from available-for-sale securities of $42.3 million; and (6) $2.9 million proceeds from the sale of assets.

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 $13.8 million, $16.3 million and $11.1 million during the years ended December 31, 2008, 2007 and 2006, respectively, of which $12.2 million, $6.9 million and $11.1 million, respectively, was to fund our share of capital expansion projects, $1.6 million in 2008 was to fund hurricane expenses and $9.4 million in 2007 was to fund working capital needs.

Net cash used in investing activities in 2006 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 Provided By Financing Activities — Net cash provided by financing activities during 2008 was comprised of; (1) proceeds from debt of $660.4 million; (2) the issuance of common units for $132.1 million, net of offering costs; (3) contributions from DCP Midstream, LLC of $4.1 million; and (4) net contributions from non-controlling interests of $2.4 million; partially offset by (5) repayment of debt of $633.9 million; and (6) distributions to our unitholders and general partner of $76.2 million.

During 2008, total outstanding indebtedness under our $824.6 million credit agreement, which includes borrowings under our revolving credit facility, our term loan facility and letters of credit issued under the credit agreement, was not less than $630.2 million and did not exceed $735.3 million. The weighted average indebtedness outstanding was $643.1 million, $690.0 million, $655.4 million and $666.6 million for the first, second, third and fourth quarters of 2008, respectively.

We had liquidity, which includes available commitments under the Credit Agreement and excludes cash on hand, of $364.7 million, $385.4 million, $390.4 million and $228.0 million at the end of the first, second, third and fourth quarters of 2008, respectively, which has been reduced by Lehman non-participation for all periods for comparative purposes.

During 2008, we had the following borrowings:

- $320.4 million borrowings for cash collateral postings with our commodity derivative contracts and for general working capital purposes. $293.9 million of these borrowings were repaid as of December 31, 2008;
- $150.0 million borrowing on our term loan facility, the proceeds of which were used to reduce borrowings on our revolving credit facility; and
- $190.0 million borrowing from our revolving credit facility, $146.4 million of which was used for the Michigan acquisition and the remainder was used for other capital expenditures.

Net cash provided by financing activities during 2007 was comprised of borrowings of $579.0 million, 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.

We expect to continue to use cash in financing activities for the payment of distributions to our unitholders and general partner. See Note 12 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.

We incur capital expenditures for our consolidated entities and our equity method investments. We anticipate maintenance capital expenditures of $10.0 to $15.0 million, and expansion capital expenditures of $65.0 million, for the year ending December 31, 2009. Maintenance capital includes an estimated $5.0 million to complete the pipeline integrity and system upgrades to our Douglas system. 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 $41.0 million and $21.3 million, including maintenance capital expenditures of $11.3 million and $2.4 million, and expansion capital expenditures of $29.7 million and $18.9 million, during 2008 and 2007, respectively. Maintenance capital in 2008 included $6.8 million associated with the pipeline integrity and system upgrades to our Douglas system. 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, 2008, we had an increase in receivables of $0.3 million and during the year ended December 31, 2007, we had a decrease in receivables of $0.2 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 $11.0 million and $2.6 million for the years ended December 31, 2008 and 2007, respectively.

During the third quarter of 2008, we announced that Collbran Valley Gas Gathering, LLC, or Collbran, plans to invest approximately $150.0 million over a multi-year period to construct approximately 20 miles of 24-inch diameter gathering pipeline, and compression and liquids handling facilities, to support its Colorado system, located in the Collbran Valley area of the Piceance Basin in western Colorado. We are the operator and 70% owner of Collbran. We ultimately expect to invest approximately $105.0 million in this project, which is in proportion to our ownership interest. The gathering system is designed to ultimately have throughput capacity of over 600 million cubic feet per day, or MMcf/d, and is supported by long-term acreage dedications. Our share of the Collbran investment was approximately $5.6 million in 2008 and we will invest approximately $57.0 million in 2009 to achieve throughput capacity of approximately 200 MMcf/d in the third quarter of 2009. Our share of the remaining investment in primarily compression equipment of approximately $42.4 million may be spent in 2010 and beyond as production volumes increase, providing total throughput capacity in excess of 600 MMcf/d.

During the third quarter of 2008, we announced plans, along with DCP Midstream, LLC, to invest approximately $56.0 million in East Texas to construct a gathering pipeline to support the East Texas system. Our interest in this pipeline is currently 25%. Our net investment is approximately $14.0 million. Of that total, we spent approximately $1.3 million in 2008 and expect to spend the remaining $12.7 million in 2009. The pipeline is scheduled to be operational during the second quarter of 2009.

During the third quarter of 2008, we announced plans to pursue development of a natural gas pipeline in the Haynesville shale in northern Louisiana. Development of a potential pipeline project is highly dependent upon drilling and development plans in the area, securing appropriate levels of shipper contractual commitments and securing financing. We spent approximately $2.3 million in 2008 on this project.

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, which could include other debt and common unit issuances, to fund our acquisition and expansion capital expenditures.

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. If these sources are not sufficient, we may reduce our capital spending.

Given our long-term strategy of profitable growth, our long-term objective is to obtain an investment grade credit rating, to increase our available sources to fund capital expenditures.

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 and general partner of $76.2 million and $44.0 million during 2008 and 2007, respectively. 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.

Description of the Credit Agreement — On June 21, 2007, we entered into an Amended and Restated Credit Agreement, or the Credit Agreement, which amended our existing Credit Agreement. This new 5-year Credit Agreement consists of a $764.6 million revolving credit facility and a $60.0 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. As of December 31, 2008, the outstanding balance on the revolving credit facility was $596.5 million and the outstanding balance on the term loan facility was $60.0 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, 2008 and 2007, there were outstanding letters of credit issued under the Credit Agreement of $0.3 million and $0.2 million, respectively.

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, 2008, the weighted-average interest rate on our revolving credit facility was 2.08% 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, 2008, the interest rate on our term loan facility was 1.54%.

The Credit Agreement prohibits us from making distributions of Available Cash to unitholders if any default or event of default (as defined in the Credit Agreement) exists. The 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 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 5.5 to 1.0. The 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 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, 2008, is as follows:

	Payments Due by Period				
	Total	2009	2010-2011	2012-2013	2014 and Thereafter
			(Millions)		
Long-term debt(a)	$ 733.4	$ 26.6	$ 42.4	$ 664.4	$ —
Operating lease obligations	44.7	12.4	16.9	12.8	2.6
Purchase obligations(b)	632.8	140.8	201.9	188.2	101.9
Other long-term liabilities(c)	8.5	—	0.4	0.1	8.0
Total	$ 1,419.4	$ 179.8	$ 261.6	$ 865.5	$ 112.5

(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 include $3.3 million of purchase orders for capital expenditures and $629.5 million of various non-cancelable commitments to purchase physical quantities of commodities in future periods. For contracts where the price paid is based on an index, the amount is based on the forward market prices at December 31, 2008. Purchase obligations exclude accounts payable, accrued interest payable and other current liabilities recognized in the consolidated balance sheets. Purchase obligations also exclude current and long-term unrealized losses on derivative instruments included in 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 $7.9 million of asset retirement obligations and $0.6 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. 162 "The Hierarchy of Generally Accepted Accounting Principles," **or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

***FASB Staff Position, or FSP, No. SFAS 142-3 "Determination of the Useful Life of Intangible Assets,"* or FSP 142-3** — In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133,"* or SFAS 161** — In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

***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. SFAS 160 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 was effective for us on January 1, 2009, and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption effective January 1, 2009, we will reclassify our non- controlling interests in the consolidated balance sheets to partners' equity.

***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 became 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;
- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and
- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not 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 recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, 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 are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial positions upon adoption.

***FSP No. 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,"* or FSP 157-3** — In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore no adjustment to our fair value methodology was required and there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, "Amendment of FASB Interpretation No. 39,"* or FSP FIN 39-1** — In April 2008, the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheets.

***EITF 08-06 "Equity Method Investment Accounting Considerations,"* or EITF 08-06 —** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee's issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us on January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

EITF 07-04 "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships" **or EITF 07-04 —** In March 2008, the EITF issued ETIF 07-04. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. This issue is effective for us on January 1, 2009 and will be incorporated into our EPU calculations beginning with the quarter ending March 31, 2009. We are in the process of assessing the impact of EITF 07-04 on our EPU calculations, and will make any required changes to our calculation methodology for the quarter ending March 31, 2009.

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 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.

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 $575.0 million of the indebtedness outstanding under our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. 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, 2008, the effective weighted-average interest rate on our $596.5 million of outstanding revolver debt was 4.48%, taking into account the $575.0 million of indebtedness with designated interest rate swaps.

Based on the annualized unhedged borrowings under our credit facility of $81.5 million as of December 31, 2008, a 0.5% movement in the base rate or LIBOR rate would result in an approximately $0.4 million annualized increase or decrease in interest expense.

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 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 fixed price 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 percent-of-proceeds arrangements and gathering operations. Historically, there has been a strong correlation between NGL prices and crude oil prices and lack of liquidity in the NGL financial market; therefore we have historically used crude oil swaps to mitigate NGL price risk. As a result of these transactions, we have mitigated a significant 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 derivative activity.

The following table sets forth additional information about our fixed price natural gas and crude oil swaps used to mitigate our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering operations:

Period	Commodity	Notional Volume	Reference Price	Swap Price Range
January 2009 — December 2009	Natural Gas	2,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2010 — December 2010	Natural Gas	1,900 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2009 — December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price(b)	$8.22/MMBtu
January 2009 — 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 2009 — December 2009	Crude Oil	2,450 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$63.05 - $86.95/Bbl
January 2010 — December 2010	Crude Oil	2,415 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$63.05 - $87.25/Bbl
January 2011 — December 2011	Crude Oil	2,350 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$66.72 - $87.25/Bbl
January 2012 — December 2012	Crude Oil	2,325 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$66.72 - $90.00/Bbl
January 2013 — December 2013	Crude Oil	1,250 Bbls/d	Asian-pricing of NYMEX crude oil futures(d)	$67.60 - $71.20/Bbl
March 2009 — December 2010(f)	Natural Gas	1,634 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas Pipeline(e)	$3.94/MMBtu
April 2010 — December 2011(f)	Crude Oil	250 Bbls/d	Asian-pricing of NYMBEX crude oil futures(d)	$56.75 - $59.30/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) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).

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

(f) These trades were entered into subsequent to December 31, 2008.

At December 31, 2008, the aggregate fair value of the fixed price natural gas and crude oil swaps described above was a net gain of $6.5 million and $13.5 million respectively.

We utilize crude oil derivatives to mitigate a significant portion of our commodity price exposure for propane and heavier NGLs. Due to current movements in the relationship of NGL prices to crude oil prices outside of recent historical ranges, we have provided an additional sensitivity factor to capture movements up or down in this relationship. We have combined the NGL and crude oil sensitivities into one factor, and added our sensitivity to changes in the relationship between the pricing of NGLs and crude oil. For fixed price natural gas and crude oil, the sensitivities are associated with our unhedged volumes. For our NGL to crude oil price relationship, the sensitivity is associated with both hedged and unhedged equity volumes. Given our current contract mix and the commodity derivative contracts we have in place, we have updated our annualized sensitivities for 2009 as shown in the table below, which excludes the impact from mark-to-market on our commodity derivatives.

Commodity Sensitivities Excluding Non-Cash Mark-To-Market

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 0.3
Crude oil prices(a)	$ 5.00	Barrel	$ 1.7
NGL to crude oil price relationship(b)	5 percentage point change	Barrel	$ 4.6

(a) Assuming 60% NGL to crude oil price relationship.

(b) Assuming 60% NGL to crude oil price relationship and $60.00/Bbl crude oil price. Generally, this sensitivity changes by $1.5 million for each $20.00/Bbl change in the price of crude oil. As crude oil prices increase from $60.00/Bbl, we become slightly more sensitive to the change in the relationship of NGL prices to crude oil prices. As crude oil prices decrease from $60.00/Bbl, we become less sensitive to the change in the relationship of NGL prices to crude oil prices.

In addition to the linear relationships in our commodity sensitivities above, additional factors cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a certain percentage of liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as NGL prices decline.

The above sensitivities exclude the impact from arrangements where producers on a monthly basis may elect to not process their natural gas in which case we retain a portion of the customers' natural gas in lieu of NGLs as a fee. The above sensitivities also exclude certain related processing arrangements where we control the processing or by-pass of the production based upon individual economic processing conditions. Under each of these types of arrangements, our processing of the natural gas would yield favorable processing margins. Less than 10% of our gas throughput is associated with these arrangements.

We estimate the following non-cash sensitivities in 2009 related to the mark-to-market on our commodity derivatives associated with our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income) (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 4.9
Crude oil prices	$ 5.00	Barrel	$ 18.8

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 in turn has been generally correlated to the price of crude oil, except in recent periods, when NGL pricing has been at a greater discount to crude oil pricing. Although the prevailing price of residue 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. The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close correlation. Changes in the correlation of the price of NGLs and crude oil may cause our commodity price sensitivities to vary. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments. As a result of these transactions, we have mitigated a significant 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.

Based on historical trends, however, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather, and the domestic production and drilling activity level of exploration and production companies. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but would likely increase commodity prices.

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 condensate. 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, 2008				
Sources of Fair Value	Total	Maturity in 2009	Maturity in 2010-2011	Maturity in 2012-2013	Maturity in 2014 and Thereafter
			(Millions)		
Prices supported by quoted market prices and other external sources	$ (21.7)	$ (2.6)	$ (15.1)	$ (4.0)	$ —
Prices based on models or other valuation techniques	2.0	0.3	1.7	—	—
Total	$ (19.7)	$ (2.3)	$ (13.4)	$ (4.0)	$ —

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, for which our fair value is based upon unadjusted quoted market prices for identical assets or liabilities in active markets. 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. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable 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 inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which 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, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), changes in partners’ equity, and cash flows for each of the three years in the period ended December 31, 2008. 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 did not audit the financial statements of Discovery Producer Services, LLC (“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 $145,054,000 and $161,519,000 at December 31, 2008 and 2007, respectively, and in Discovery’s net income of $13,760,000, $19,229,000, and $12,033,000 for the years ended December 31, 2008, 2007 and 2006, 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 the 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, 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 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 DCP Midstream, LLC (“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 through July 1, 2007, the portion of the accompanying consolidated financial statements attributable to DCP East Texas Holdings, LLC (“East Texas”) , Discovery and a nontrading derivative instrument (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, 2008, 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 4, 2009 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte & Touche LLP
Denver, Colorado
March 4, 2009

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 48.0	$ 24.5
Short-term investments	—	1.3
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.6 million and $1.2 million, respectively	43.6	81.7
Affiliates	36.8	52.1
Inventories	20.9	37.3
Unrealized gains on derivative instruments	15.4	3.1
Other	0.5	18.5
Total current assets	165.2	218.5
Restricted investments	60.2	100.5
Property, plant and equipment, net	629.3	500.7
Goodwill	88.8	80.2
Intangible assets, net	47.7	29.7
Equity method investments	175.4	187.2
Unrealized gains on derivative instruments	8.6	2.7
Other long-term assets	4.8	1.2
Total assets	$ 1,180.0	$ 1,120.7
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 44.8	$ 110.2
Affiliates	33.6	55.6
Unrealized losses on derivative instruments	17.7	30.9
Accrued interest payable	1.3	1.6
Other	27.4	21.3
Total current liabilities	124.8	219.6
Long-term debt	656.5	630.0
Unrealized losses on derivative instruments	26.0	70.0
Other long-term liabilities	8.9	5.8
Total liabilities	816.2	925.4
Non-controlling interests	34.7	26.9
Commitments and contingent liabilities		
Partners' equity:		
Common unitholders (24,661,754 and 16,840,326 units issued and outstanding, respectively)	429.0	308.8
Subordinated unitholders (3,571,429 and 7,142,857 convertible units issued and outstanding, respectively)	(54.6)	(120.1)
General partner interest	(4.8)	(5.4)
Accumulated other comprehensive loss	(40.5)	(14.9)
Total partners' equity	329.1	168.4
Total liabilities and partners' equity	$ 1,180.0	$ 1,120.7

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(Millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, propane, NGLs and condensate	$ 678.5	$ 628.1	$ 535.1
Sales of natural gas, propane, NGLs and condensate to affiliates	477.8	297.7	232.8
Transportation, processing and other	31.2	18.5	15.0
Transportation, processing and other to affiliates	26.0	16.6	12.8
Gains (losses) from commodity derivative activity, net	75.4	(83.1)	—
(Losses) gains from commodity derivative activity, net — affiliates	(3.1)	(4.5)	0.1
Total operating revenues	1,285.8	873.3	795.8
Operating costs and expenses:			
Purchases of natural gas, propane and NGLs	798.3	647.4	581.2
Purchases of natural gas, propane and NGLs from affiliates	262.9	179.3	119.2
Operating and maintenance expense	43.0	32.1	23.7
Depreciation and amortization expense	36.5	24.4	12.8
General and administrative expense	12.4	14.1	12.9
General and administrative expense — affiliates	11.6	10.0	8.1
Other	(1.5)	—	—
Total operating costs and expenses	1,163.2	907.3	757.9
Operating income (loss)	122.6	(34.0)	37.9
Interest income	5.6	5.3	6.3
Interest expense	(32.8)	(25.8)	(11.5)
Earnings from equity method investments	34.3	39.3	29.2
Non-controlling interest in income	(3.9)	(0.5)	—
Income (loss) before income taxes	125.8	(15.7)	61.9
Income tax expense	(0.1)	(0.1)	—
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Less:			
Net income attributable to predecessor operations	—	(3.6)	(26.6)
General partner interest in net income	(11.9)	(2.2)	(0.7)
Net income (loss) allocable to limited partners	$ 113.8	$ (21.6)	$ 34.6
Net income (loss) per limited partner unit — basic and diluted	$ 3.25	$ (1.05)	$ 1.90
Weighted-average limited partner units outstanding — basic and diluted	27.4	20.5	17.5

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Other comprehensive income (loss):			
Reclassification of cash flow hedges into earnings	7.5	(3.1)	(2.7)
Net unrealized (losses) gains on cash flow hedges	(33.1)	(19.1)	9.6
Total other comprehensive (loss) income	(25.6)	(22.2)	6.9
Total comprehensive income (loss)	$ 100.1	$ (38.0)	$ 68.8

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	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
				(Millions)			
Balance, January 1, 2006	$ 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
Issuance of 4,250,000 common units	—	132.1	—	—	—	—	132.1
Conversion of subordinated units to common units		(66.4)	—	66.4	—	—	—
Contributions by unitholders	—	4.0	—	—	—	—	4.0
Distributions to unitholders and general partner	—	(53.9)	—	(10.5)	(11.3)	—	(75.7)
Equity-based compensation	—	0.2	—	—	—	—	0.2
Net income	—	104.2	—	9.6	11.9	—	125.7
Other comprehensive loss	—	—	—	—	—	(25.6)	(25.6)
Balance, December 31, 2008	$ —	$ 429.0	$ —	$ (54.6)	$ (4.8)	$ (40.5)	$ 329.1

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
		(Millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense	36.5	24.4	12.8
Earnings from equity method investments, net of distributions	25.6	(0.4)	(3.3)
Non-controlling interest in income	3.9	0.5	—
Other, net	(0.4)	(0.2)	(2.4)
Change in operating assets and liabilities which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	55.4	(42.2)	43.1
Inventories	16.4	(7.2)	11.6
Net unrealized (gains) losses on derivative instruments	(101.0)	81.1	(0.1)
Accounts payable	(79.7)	38.9	(31.5)
Accrued interest	(0.3)	0.5	0.3
Other current assets and liabilities	19.8	(16.4)	2.0
Other long-term assets and liabilities	(0.4)	2.2	0.4
Net cash provided by operating activities	101.5	65.4	94.8
INVESTING ACTIVITIES:			
Capital expenditures	(41.0)	(21.3)	(27.2)
Acquisition of Michigan Pipeline & Processing, LLC, net of cash acquired	(146.4)	—	—
Acquisition of subsidiaries of Momentum Energy Group, Inc., net of cash acquired	(10.9)	(142.0)	—
Acquisition of assets	—	(191.3)	—
Acquisition of equity method investments	—	(153.3)	—
Investments in equity method investments	(13.8)	(16.3)	(11.1)
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	2.9	0.1	0.3
Purchases of available-for-sale securities	(608.2)	(6,921.6)	(7,372.4)
Proceeds from sales of available-for-sale securities	650.5	6,924.0	7,373.3
Net cash used in investing activities	(166.9)	(521.7)	(93.8)
FINANCING ACTIVITIES:			
Proceeds from debt	660.4	579.0	78.0
Payments of debt	(633.9)	(217.0)	(20.1)
Payment of deferred financing costs	—	(0.6)	(0.2)
Purchase of units	—	(0.3)	—
Proceeds from issuance of common units, net of offering costs	132.1	228.5	—
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)
Distributions to unitholders and general partner	(76.2)	(44.0)	(22.1)
Distributions to non-controlling interests	(3.3)	—	—
Contributions from non-controlling interests	5.7	3.4	—
Contributions from DCP Midstream, LLC	4.1	0.5	3.4
Net cash provided by financing activities	88.9	434.6	3.0
Net change in cash and cash equivalents	23.5	(21.7)	4.0
Cash and cash equivalents, beginning of period	24.5	46.2	42.2
Cash and cash equivalents, end of period	$ 48.0	$ 24.5	$ 46.2

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2008, 2007 and 2006

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 Michigan systems (acquired in October 2008); 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 30% 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 our Southern Oklahoma, Wyoming and Colorado systems, and our Michigan systems, have been included in the consolidated financial statements since their respective acquisition dates.

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 income (loss), 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. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

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 customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit.

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 (1) 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; and (2) the non controlling interest holders' portion of the net assets of Jackson Pipeline Company, a partnership we acquired with the Michigan acquisition in October 2008. 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 underlying 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.
- *Percent-of-proceeds arrangements* — Under percent-of-proceeds 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 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, credit metrics, liquidity 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 cash 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 commodity derivative activity net in the consolidated statements of operations as gains and losses from commodity derivative activity. These activities include mark-to-market gains and losses on energy trading contracts and the settlement of financial or physical 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 $3.8 million and $1.6 million at December 31, 2008 and 2007, respectively. Included in the consolidated balance sheets as accounts payable — trade were imbalances of $1.4 million and $1.1 million at December 31, 2008 and 2007, 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, 2008, 2007 and 2006. In addition, there were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2008, 2007 and 2006 in any of our business segments. We also had significant transactions with affiliates, and with suppliers of natural gas and propane.

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, 2008 and 2007, included in the consolidated balance sheets as other current liabilities amounted to $1.3 million and $0.7 million, respectively, and as other long-term liabilities amounted to $0.6 million and $1.0 million, respectively.

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 income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this 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. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

Comprehensive Income or Loss — Comprehensive income or loss 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 or Loss per Limited Partner Unit — Basic and diluted net income or loss per limited partner unit is calculated by dividing limited partners' interest in net income or loss, 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. 162 "The Hierarchy of Generally Accepted Accounting Principles,"* or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

***FASB Staff Position, or FSP, No. SFAS 142-3 "Determination of the Useful Life of Intangible Assets,"* or FSP 142-3** — In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3, but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133,"* or SFAS 161** — In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

***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. SFAS 160 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 was effective for us on January 1, 2009, and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption effective January 1, 2009, we will reclassify non-controlling interests in the consolidated balance sheets to partners' equity.

***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 became 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;
- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and
- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not 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 recorded a transition adjustment of approximately $5.8 million as an increase to earnings and approximately $1.3 million as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, 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 are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial position upon adoption.

***FSP No. 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,"* or FSP 157-3** — In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, "Amendment of FASB Interpretation No. 39,"* or FSP FIN 39-1** — In April 2007, the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheets.

***EITF 08-06 "Equity Method Investment Accounting Considerations,"* or EITF 08-06 —** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee's issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us on January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

***EITF 07-04 "Application of the Two — Class Method under FASB Statement No. 128 to Master Limited Partnerships"* or EITF 07-04 —** In March 2008, the EITF issued ETIF 07-04. This issue seeks to improve the comparability of earnings per unit, or EPU, calculations for master limited partnerships with incentive distribution rights in accordance with FASB Statement No. 128 and its related interpretations. This issue is effective for us on January 1, 2009 and will be incorporated into our EPU calculations beginning with the quarter ending March 31, 2009. We are in the process of assessing the impact of EITF 07-04 on our EPU calculations, and will make any required changes to our calculation methodology for the quarter ending March 31, 2009.

4. Acquisitions

Gathering and Compression Assets

On October 1, 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. The results of MPP's operations have been included in the consolidated financial statements since that date. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million, subject to additional customary purchase price adjustments. We may pay up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied, and as a result, the amount was reduced to approximately $0.8 million per year as of December 31, 2008. We initially held a $25.0 million letter of credit to secure the seller's performance under this agreement and to secure the seller's indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $22.5 million as of December 31, 2008. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $6.7 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained, which when finalized may result in material adjustments. The purchase price allocation is as follows:

	(Millions)
Cash	$ 1.7
Accounts receivable	2.1
Other assets	0.1
Other long term assets	3.8
Property, plant and equipment	116.1
Goodwill	6.7
Intangible assets	20.0
Other liabilities	(0.5)
Non-controlling interest in joint venture	(1.6)
Total purchase price allocation	$ 148.4

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 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 totaling $10.9 million for net working capital and general and administrative charges. We financed this transaction with $120.0 million of borrowings under our 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 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, and we recorded goodwill of approximately $52.8 million, including purchase price adjustments of $1.9 million during the first quarter of

2008. 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. The purchase price allocation is as follows:

	(Millions)
Cash consideration	$ 153.8
Payable to DCP Midstream, LLC	10.9
Common limited partner units	12.0
Aggregate consideration	$ 176.7
The purchase price allocation is as follows:	
Cash	$ 11.8
Accounts receivable	14.1
Other assets	1.5
Property, plant and equipment	127.8
Goodwill	52.8
Intangible assets	15.5
Accounts payable	(11.1)
Other liabilities	(12.9)
Non-controlling interest in joint venture	(22.8)
Total purchase price allocation	$ 176.7

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, 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 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.

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 MPP, MEG, 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 pro forma information for the consolidated statements of operations for the years ended 2008 and 2007, as if the acquisition of MPP had occurred at the beginning of each year presented. There is no impact shown for the MEG acquisition because there were no predecessor operations of MEG at DCP Midstream, LLC.

	2008			2007		
	DCP Midstream Partners, LP	Acquisition of MPP	DCP Midstream Partners, LP Pro Forma	DCP Midstream Partners, LP	Acquisition of MPP	DCP Midstream Partners, LP Pro Forma
	(Millions, except per unit amounts)					
Total operating revenues	$ 1,285.8	$ 14.8	$ 1,300.6	$ 873.3	$ 20.9	$ 894.2
Net income (loss)	$ 125.7	$ 2.2	$ 127.9	$ (15.8)	$ 1.2	$ (14.6)
Less:						
Net income attributable to predecessor operations	—	—	—	(3.6)	—	(3.6)
General partner interest in net income	(11.9)	—	(11.9)	(2.2)	(0.1)	(2.3)
Net income (loss) allocable to limited partners	$ 113.8	$ 2.2	$ 116.0	$ (21.6)	$ 1.1	$ (20.5)
Net income (loss) per limited partner unit — basic and diluted	$ 3.25	$ 0.04	$ 3.29	$ (1.05)	$ 0.05	$ (1.00)

The pro forma information is not intended to reflect actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by us in the future.

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. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $43.0 million at December 31, 2008, to certain counterparties to our commodity derivative instruments.

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 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, 2008	2007	2006
			(Millions)	
Annual fee	2006	$ 5.1	$ 5.0	$ 4.8
Wholesale propane logistics business	November 2006	2.0	2.0	0.3
Southern Oklahoma	May 2007	0.2	0.1	—
Discovery	July 2007	0.2	0.1	—
Additional services	August 2007	0.6	0.2	—
Momentum Energy Group, Inc.	August 2007	1.6	0.5	—
Michigan Pipeline & Processing, LLC	October 2008	0.1	—	—
Total Omnibus Agreement		9.8	7.9	5.1
Other fees		1.8	2.1	3.0
Total		$ 11.6	$ 10.0	$ 8.1

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

The Black Lake pipeline has experienced increased operating costs due to pipeline integrity testing that commenced in 2005 and was completed during the second quarter of 2008. Testing revealed irregularities, the more severe of which were repaired in October 2008 and the less severe of which are scheduled for repair in 2009. DCP Midstream, LLC agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC 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 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, LLC 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.

We have not pursued indemnification under these agreements.

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, processing and other services to affiliates.

In addition, we sell NGLs processed at our Minden and Ada plants, and sell condensate removed from the gas gathering systems that deliver to the Minden and Ada plants, and from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation, processing 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, processing and other 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, processing and other services to affiliates.

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

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 $3.8 million and $0.3 million during 2008 and 2007, respectively to reimburse us for these capital projects, which were substantially completed in 2008.

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 July 2008, DCP Midstream, LLC issued additional parental guarantees outside of the Omnibus Agreement, totaling $200.0 million, to certain counterparties to our commodity derivative instruments to mitigate a portion of our collateral requirements with those counterparties. These guarantees were reduced to $65.0 million as of December 31, 2008 to correspond with lower commodity prices and collateral requirements. We pay DCP Midstream, LLC interest of 0.5% per annum on these outstanding guarantees.

DCP Midstream, LLC was a significant customer during the years ended December 31, 2008, 2007 and 2006.

Duke Energy

Prior to December 31, 2006, we purchased natural gas from Duke Energy and its affiliates.

Spectra Energy

We purchase a portion of our propane from and market propane on behalf of Spectra Energy. We anticipate continuing to purchase propane from and market propane on behalf of Spectra Energy in the ordinary course of business.

During the second quarter of 2008, we entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides us propane supply at our marine terminal, which is included in our Wholesale Propane Logistics segment, for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated for non-performance during the first quarter of 2008.

ConocoPhillips

We have multiple agreements whereby we provide a variety of services to ConocoPhillips and its affiliates. The agreements include fee-based and percent-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 $1.9 million, $2.9 million and $3.9 million of capital reimbursements during the years ended December 31, 2008, 2007 and 2006, respectively.

The following table summarizes the transactions with affiliates:

	Year Ended December 31, 2008	2007	2006
	(Millions)		
DCP Midstream, LLC:			
Sales of natural gas, propane, NGLs and condensate	$ 475.7	$ 290.0	$ 231.7
Transportation, processing and other	$ 15.4	$ 6.0	$ 4.8
Purchases of natural gas, propane and NGLs	$ 175.3	$ 150.1	$ 102.9
(Losses) gains from derivative activity, net	$ (3.1)	$ (4.5)	$ 0.1
Operating and maintenance expense	$ —	$ 0.4	$ 0.2
General and administrative expense	$ 11.6	$ 10.0	$ 8.1
Interest expense	$ 0.4	$ —	$ —
Spectra Energy:			
Sales of natural gas, propane, NGLs and condensate	$ 0.3	$ 1.1	$ —
Transportation, processing and other	$ 0.2	$ —	$ —
Purchases of natural gas, propane and NGLs	$ 51.0	$ —	$ —
Duke Energy:			
Purchases of natural gas, propane and NGLs	$ —	$ —	$ 3.4
ConocoPhillips:			
Sales of natural gas, propane, NGLs and condensate	$ 1.8	$ 6.6	$ 1.1
Transportation, processing and other	$ 10.4	$ 10.6	$ 8.0
Purchases of natural gas, propane and NGLs	$ 36.6	$ 29.2	$ 12.9

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

	December 31, 2008	2007
	(Millions)	
DCP Midstream, LLC:		
Accounts receivable	$ 30.3	$ 47.3
Accounts payable	$ 27.9	$ 53.3
Spectra Energy:		
Accounts receivable	$ 4.0	$ 1.5
Accounts payable	$ 5.3	$ —
ConocoPhillips:		
Accounts receivable	$ 2.5	$ 3.3
Accounts payable	$ 0.4	$ 2.3

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

	December 31, 2008	2007
	(Millions)	
DCP Midstream, LLC:		
Unrealized losses — current	$ (1.2)	$ (2.7)

6. Property, Plant and Equipment

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

	Depreciable Life	December 31, 2008	December 31, 2007
		(Millions)	
Gathering systems	15 — 30 Years	$ 405.0	$ 371.3
Processing plants	25 — 30 Years	163.4	91.4
Terminals	25 — 30 Years	28.5	24.2
Transportation	25 — 30 Years	174.0	141.0
General plant	3 — 5 Years	6.0	4.0
Construction work in progress		43.5	25.5
Property, plant and equipment		820.4	657.4
Accumulated depreciation		(191.1)	(156.7)
Property, plant and equipment, net		$ 629.3	$ 500.7

The above amounts include accrued capital expenditures of $12.3 million and $8.4 million as of December 31, 2008 and 2007, respectively, which are included in other current liabilities in the consolidated balance sheets.

Depreciation expense was $34.4 million, $23.3 million and $12.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We lease one of our Michigan transmission pipelines to a third party under a long-term contract. The carrying value of the pipeline is approximately $23.0 million, with accumulated depreciation of $0.2 million. Minimum future non-cancelable rental payments are as follows:

	Rental Payments (Millions)
2009	$ 3.0
2010	2.9
2011	2.9
2012	2.8
2013	2.3
Thereafter	20.7
Total	$ 34.6

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 $7.9 million and $3.1 million at December 31, 2008 and 2007, respectively. The asset retirement obligation increased in 2008 and 2007, respectively, as a result of the MPP and MEG acquisitions. Accretion expense for the years ended December 31, 2008 and 2007 was $0.4 million and $0.1 million, respectively, and for the year ended December 31, 2006 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,	
	2008	2007
	(Millions)	
Beginning of period	$ 80.2	$ 29.3
Acquisitions	8.6	50.9
End of period	$ 88.8	$ 80.2

Goodwill increased during 2008 by $6.7 million as a result of the MPP acquisition, and by $1.9 million for the final purchase price allocation for the MEG subsidiaries acquired from DCP Midstream, LLC. The increase in goodwill during 2007 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.

During the fourth quarter of 2008, as a result of the decline in the general equity market indices and in our unit price on the New York Stock exchange, we updated our fair value analysis using current marketplace assumptions and concluded that the carrying value of goodwill is recoverable; therefore, we did not record any impairment charges during the years ended December 31, 2008, 2007 and 2006. However, given the current volatility in the equity market, as well as volatile commodity prices, we will continue to monitor the recoverability of such amounts. Continued volatility and marketplace activity may alter our conclusion in the future, and could result in the recognition of an impairment charge.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related 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,	
	2008	2007
	(Millions)	
Gross carrying amount	$ 52.5	$ 32.4
Accumulated amortization	(4.8)	(2.7)
Intangible assets, net	$ 47.7	$ 29.7

Intangible assets increased in 2008 as a result of the MPP acquisition.

For the years ended December 31, 2008, 2007 and 2006, we recorded amortization expense of $2.1 million, $1.1 million and $0.4 million, respectively. As of December 31, 2008, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 21 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(Millions)
2009	$ 2.6
2010	2.6
2011	2.3
2012	2.3
2013	2.3
Thereafter	35.6
Total	$ 47.7

8. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of December 31, 2008 and 2007	Carrying Value as of December 31, 2008	Carrying Value as of December 31, 2007
		(Millions)	
Discovery Producer Services LLC	40%	$ 105.0	$ 117.9
DCP East Texas Holdings, LLC	25%	63.9	62.9
Black Lake Pipe Line Company	45%	6.3	6.2
Other	50%	0.2	0.2
Total equity method investments		$ 175.4	$ 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 $39.7 million and $43.7 million at December 31, 2008 and 2007, 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 900-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 $6.0 million and $6.4 million at December 31, 2008 and 2007, respectively, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

Earnings from equity method investments were as follows:

	Year Ended December 31,		
	2008	2007 (Millions)	2006
Discovery Producer Services LLC	$ 17.4	$ 24.1	$ 16.9
DCP East Texas Holdings, LLC	16.1	14.6	12.0
Black Lake Pipe Line Company and other	0.8	0.6	0.3
Total earnings from equity method investments	$ 34.3	$ 39.3	$ 29.2
Distributions from equity method investments	$ 59.9	$ 38.9	$ 25.9
Earnings from equity method investments, net of distributions	$ (25.6)	$ 0.4	$ 3.3

The following summarizes financial information of our equity method investments:

	Year Ended December 31,		
	2008	2007 (Millions)	2006
Statements of operations:			
Operating revenue	$ 792.7	$ 739.6	$ 686.9
Operating expenses	$ (696.9)	$ 634.6	$ 612.2
Net income	$ 99.8	$ 106.8	$ 77.4

	December 31,	
	2008 (Millions)	2007
Balance sheet:		
Current assets	$ 104.3	$ 168.8
Long-term assets	646.3	630.3
Current liabilities	(84.4)	(100.9)
Long-term liabilities	(22.4)	(14.9)
Net assets	$ 643.8	$ 683.3

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 13 Risk Management Activities Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and a market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected correlation of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar duration, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or more, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2008, nearly all of our short-term and restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department’s Temporary Guarantee Program for Money Market Funds.

The following table presents the financial instruments carried at fair value as of December 31, 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices in Active Markets (Level 1)	Internal Models with Significant Observable Market Inputs (Level 2)	Internal Models with Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
		(Millions)		
Current assets:				
Commodity derivative instruments(a)	$ —	$ 15.1	$ 0.3	$ 15.4
Long-term assets:				
Restricted investments	$ —	$ 60.2	$ —	$ 60.2
Commodity derivative instruments(b)	$ —	$ 6.9	$ 1.7	$ 8.6
Interest rate instruments(b)	$ —	$ —	$ —	$ —
Current liabilities(c):				
Commodity derivative instruments	$ —	$ (1.2)	$ —	$ (1.2)
Interest rate instruments	$ —	$ (16.5)	$ —	$ (16.5)
Long-term liabilities(d):				
Commodity derivative instruments	$ —	$ (3.2)	$ —	$ (3.2)
Interest rate instruments	$ —	$ (22.8)	$ —	$ (22.8)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.

(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.

(c) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.

(d) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the "Transfers In/Out of Level 3" caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Balance at December 31, 2007	Net Realized and Unrealized Gains Included in (Losses) Earnings	Transfers In/ Out of Level 3(a)	Purchases, Issuances and Settlements, Net	Balance at December 31, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings(b)
			(Millions)			
Commodity derivative instruments:						
Current assets	$ 0.2	$ 0.8	$ —	$ (0.7)	$ 0.3	$ 0.3
Long-term assets	$ 1.5	$ 1.0	$ (0.8)	$ —	$ 1.7	$ 1.0
Current liabilities	$ (1.6)	$ (0.2)	$ —	$ 1.8	$ —	$ —
Long-term liabilities	$ (0.2)	$ 0.2	$ —	$ —	$ —	$ 0.2

(a) Amounts transferred in are reflected at fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

(b) Represents the amount of total gains or losses for the period, included in gains or losses from commodity derivative activity, net, attributable to change in unrealized gains (losses) relating to assets and liabilities classified as Level 3 that are still held at December 31, 2008.

10. Estimated Fair Value of Financial Instruments

We have determined 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 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.

11. Debt

Long-term debt was as follows:

	Principal Amount 2008	2007
	(Millions)	
Revolving credit facility, weighed-average interest rate of 2.08% and 5.47%, respectively, due June 21, 2012(a)	$ 596.5	$ 530.0
Term loan facility, interest rate 1.54% and 5.05%, respectively, due June 21, 2012(b)	60.0	100.0
Total long-term debt	$ 656.5	$ 630.0

(a) $575.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.48% on the $596.5 million of outstanding debt under our revolving credit facility as of December 31, 2008.

(b) The term loan facility is fully secured by restricted investments.

Credit Agreement

We have an $824.6 million 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, which consists of:

- a $764.6 million revolving credit facility; and
- a $60.0 million term loan facility.

At December 31, 2008 and 2007, we had $0.3 million and $0.2 million of letters of credit issued under the credit agreement outstanding, respectively. 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, 2008 and 2007. As of December 31, 2008, the available capacity under the revolving credit facility was $171.5 million, which is net of approximately $21.7 million non-participation by Lehman Brothers Commercial Bank, or Lehman Brothers, as discussed below. We incurred $0.6 million of debt issuance costs during 2007 associated with the 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 Credit Agreement.

Under the 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 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 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 5.5 to 1.0. The 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 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.

Lehman Brothers is a lender in our Credit Agreement. Lehman Brothers has not funded its portion of our borrowing requests since its bankruptcy, and it is uncertain whether it will participate in future borrowing requests. Accordingly, the availability of new borrowings under the Credit Agreement has been reduced by approximately $25.4 million as of December 31, 2008. Our borrowing capacity may be further limited by the Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

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.

Other Agreements

As of December 31, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million, which reduces the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility.

12. 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.

In March 2008, we issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

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 has not participated in certain issuances of common units. Therefore, the general partner's 2% interest has been diluted to approximately 1% as of December 31, 2008.

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. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. 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. In 2008, 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, or 3,571,428 units, converted into common units. We determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2009 and, therefore, the remaining 3,571,429 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 approximately 1%, 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.

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The following table presents our cash distributions paid in 2008, 2007 and 2006:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2008	$ 0.600	$ 20.1
August 14, 2008	0.600	20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7
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.

13. 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, 2008	2007 (Millions)	2006
Commodity cash flow hedges:			
Losses due to ineffectiveness	$ —	$ —	$ (0.3)
(Losses) gains reclassified into earnings	$ (0.8)	$ 2.4	$ 2.6
Commodity derivative activity:			
Unrealized gains (losses) from derivative activity	$ 102.4	$ (81.7)	$ 0.3
Realized losses from derivative activity	$ (30.1)	$ (5.9)	$ (0.2)
Interest rate cash flow hedges:			
(Losses) gains reclassified into earnings	$ (6.7)	$ 0.7	$ 0.1

	December 31, 2008	2007
	(Millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (1.8)	$ (2.6)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	$ (38.7)	$ (12.3)

For the years ended December 31, 2008, 2007 and 2006, 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. As of December 31, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million. This letter of credit reduces the amount of cash we may be required to post as collateral. As of December 31, 2008, we had no cash collateral posted with counterparties to our commodity derivative instruments.

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 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 underlying transactions impact earnings. As of December 31, 2008, deferred net losses of $0.9 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. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

As of December 31, 2008, we have mitigated a significant 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 commodities in future periods as well as select operating expense contracts.

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 $575.0 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, 2008, $16.0 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. $425.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% 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

Total compensation (credit) cost for equity-based arrangements was as follows:

	Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Performance Units	$ (0.7)	$ 1.1	$ 0.2
Phantom Units	(0.4)	0.6	0.4
Restricted Phantom Units	0.1	—	—
Total compensation (credit) cost	$ (1.0)	$ 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.

All 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 200% 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, 2008, 21,705 units vested in January 2009, 15,101 units are expected to vest on December 31, 2009, and 8,544 units are expected to vest on December 31, 2010.

At December 31, 2008, there was approximately $0.3 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 0.7 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 January 1, 2006	—	$ —	
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	
Granted	17,085	$ 33.85	
Forfeited	(12,025)	$ 32.42	
Outstanding at December 31, 2008	52,020	$ 33.35	$ 9.40
Expected to vest(a)	45,350	$ 31.70	$ 9.40

(a) Based on our December 31, 2008 estimated achievement of specified performance targets, the performance target for units granted in 2008 is 100%, for units granted in 2007 is 102%, and for units granted in 2006 is 140.4%. The estimated forfeiture rate for units granted in 2008 and 2007 is 50%, and for units granted in 2006 is 0%.

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. The remaining Phantom Units outstanding at December 31, 2008 vested 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 units, 4,000 units vested during 2007 and 500 units vested in February 2008.

In 2008, we granted 4,000 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 2008. All of these units vested during 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 Price per Unit
Outstanding at January 1, 2006	—	$ —	
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	
Granted	4,000	$ 35.88	
Forfeited	(4,000)	$ 24.05	
Vested	(6,501)	$ 32.91	
Outstanding at December 31, 2008	13,698	$ 24.05	$ 9.40
Expected to vest	13,698	$ 24.05	$ 9.40

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.

Restricted Phantom Units — Our General Partner’s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs outstanding at December 31, 2008 are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears.

At December 31, 2008, there was approximately $0.2 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of 2.0 years. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2008	—	$ —	$ —
Granted	17,085	$ 33.85	
Forfeited	(2,395)	$ 35.88	
Vested	—	$ —	
Outstanding at December 31, 2008	14,690	$ 33.52	$ 9.40
Expected to vest	8,544	$ 33.85	$ 9.40

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 50% as of December 31, 2008. 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 certain awards issued under the LTIP in cash upon vesting. Compensation expense on these awards is recognized ratably over each vesting period, and will be remeasured each reporting period 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.

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, 2008, 2007 and 2006, and no federal income tax expense for the years ended December 31, 2008, 2007 and 2006.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. During 2008 we acquired properties in Michigan. Michigan imposes a business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. The sum of the gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final tax liability.

Income tax expense for the years ended December 31, 2008 and 2007, consisted of current expense of $0.1 million for both periods, related primarily to the Texas margin tax. We did not have income tax expense in 2006. 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.

16. Net Income or Loss per Limited Partner Unit

Our net income or loss 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 loss 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, 2008, our aggregate net income per limited partner unit exceeded the Fourth Target Distribution level, and as a result we allocated an additional $24.8 million in additional earnings to the general partner. 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 or loss per LPU is calculated by dividing limited partners’ interest in net income or loss, 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, 2008	2007 (Millions)	2006
Net income (loss)	$ 125.7	$ (15.8)	$ 61.9
Less:			
Net income attributable to predecessor operations	—	(3.6)	(26.6)
Net income (loss) attributable to the partnership	125.7	(19.4)	35.3
Less: General partner interest in net income	(11.9)	(2.2)	(0.7)
Limited partners' interest in net income or net loss	113.8	(21.6)	34.6
Less: Additional earnings allocation to general partner	(24.8)	—	(1.3)
Net income (loss) available to limited partners	$ 89.0	$ (21.6)	$ 33.3
Net income (loss) per LPU — basic and diluted	$ 3.25	$ (1.05)	$ 1.90

17. 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 — On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008.

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. 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) property insurance, which covers replacement value of all real and personal property and includes business interruption/ extra expense and (5) 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, totaled $12.9 million, $11.4 million and $11.2 million for the years ended December 31, 2008, 2007 and 2006, 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, 2008:

	(Millions)
2009	$ 12.4
2010	9.0
2011	7.9
2012	7.0
2013	5.8
Thereafter	2.6
Total minimum rental payments	$ 44.7

18. 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) 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; (4) our Colorado and Wyoming systems, acquired in August 2007; and (5) our Michigan systems, acquired in October 2008.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which was idled in 2007 to consolidate our operations, 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, 2008:

	Natural Gas Services	Wholesale Propane Logistics	NGL Logistics	Other(c)	Total
			(Millions)		
Total operating revenue	$ 791.5	$ 483.0	$ 11.3	$ —	$ 1,285.8
Gross margin(a)	$ 206.5	$ 11.0	$ 7.1	$ —	$ 224.6
Operating and maintenance expense	(32.1)	(9.9)	(1.0)	—	(43.0)
Depreciation and amortization expense	(33.8)	(1.3)	(1.4)	—	(36.5)
General and administrative expense	—	—	—	(24.0)	(24.0)
Other	—	1.5	—	—	1.5
Earnings from equity method investments	33.5	—	0.8	—	34.3
Interest income	—	—	—	5.6	5.6
Interest expense	—	—	—	(32.8)	(32.8)
Income tax expense(b)	—	—	—	(0.1)	(0.1)
Non-controlling interest in income	(3.9)	—	—	—	(3.9)
Net income (loss)	$ 170.2	$ 1.3	$ 5.5	$ (51.3)	$ 125.7
Non-cash derivative mark-to-market(d)	$ 99.2	$ 2.4	$ —	$ (0.6)	$ 101.0
Capital expenditures	$ 36.6	$ 3.3	$ 0.4	$ 0.7	$ 41.0

DCP MIDSTREAM PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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)
Non-cash derivative mark-to-market(d)	$ (78.3)	$ (2.8)	$ —	$ —	$ (81.1)
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
Non-cash derivative mark-to-market(d)	$ 0.1	$ —	$ —	$ —	$ 0.1
Capital expenditures	$ 6.5	$ 9.4	$ 11.3	$ —	$ 27.2

	December 31, 2008	December 31, 2007
	(Millions)	
Segment long-term assets:		
Natural Gas Services(e)	$ 856.4	$ 710.7
Wholesale Propane Logistics	54.3	52.6
NGL Logistics	33.8	34.8
Other(f)	70.3	104.1
Total long-term assets	1,014.8	902.2
Current assets	165.2	218.5
Total assets	$ 1,180.0	$ 1,120.7

(a) Gross margin consists of total operating revenues, including commodity derivative activity, 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 2008 and 2007 relates primarily to the Texas margin tax.

(c) Other consists of general and administrative expense, interest income, interest expense and income tax expense.

(d) Non-cash derivative mark-to-market is included in segment gross margin, along with cash settlements for our derivative contracts.

(e) Long-term assets for our Natural Gas Services segment increased in 2008 as a result of our acquisition of MPP in October 2008, and 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.

(f) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, corporate leasehold improvements and other long-term assets.

19. Supplemental Cash Flow Information

	Year Ended December 31, 2008	2007 (Millions)	2006
Cash paid for interest:			
Cash paid for interest, net of amounts capitalized	$ 26.3	$ 26.5	$ 11.1
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 1.5	$ 5.9	$ 1.4
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	$ 0.2	$ —

20. Quarterly Financial Data (Unaudited)

Our consolidated results of operations by quarter for the years ended December 31, 2008, 2007 and 2006 were as follows (millions, except per unit amounts):

2008	First	Second	Third	Fourth	Year Ended December 31, 2008
Total operating revenues	$ 337.7	$ 145.9	$ 426.8	$ 375.4	$ 1,285.8
Operating (loss) income	$ (16.6)	$ (165.7)	$ 152.4	$ 152.5	$ 122.6
Net (loss) income	$ (6.5)	$ (159.3)	$ 152.7	$ 138.8	$ 125.7
Limited partners' interest in net (loss) income	$ (8.2)	$ (159.8)	$ 147.8	$ 134.0	$ 113.8
Basic net (loss) income per limited partner unit	$ (0.33)	$ (5.66)	$ 2.97	$ 2.72	$ 3.25

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, 2006 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.

21. Subsequent Events

On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated financial statements for the year ended December 31, 2008.

On February 25, 2009, we entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to us in exchange for 3.5 million Class D units, providing us with a 50.1% interest in East Texas following the expected closing of the transaction in April 2009. This closing date is subject to extension for up to 45 days to allow for repairs or replacement to our reasonable satisfaction any assets destroyed or damaged by certain casualty losses and time to enable the plant to process all available inlet volumes as defined in the Contribution Agreement. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC has agreed to provide a fixed-price NGL derivative by NGL component for the period of April 2009 to March 2010 for the acquired interest. Subsequent to this transaction, we will consolidate East Texas in our consolidated financial statements.

On February 11, 2009, we announced, along with DCP Midstream, LLC, that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

On February 17, 2009, the remaining 3,571,429 DCP Partners subordinated units were converted to common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners' partnership agreement.

In February 2009, we entered into interest rate swap agreements to convert $275.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps commence in December 2010 and expire in June 2012

On January 27, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

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, 2008.

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, 2008, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2008, our disclosure controls and procedures were effective. There were no 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 2008 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, 2008 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, 2008.

Deloitte & Touche, LLP, an independent registered public accounting firm, has issued their report, included immediately following, regarding our internal control over financial reporting.

March 4, 2009

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, 2008, 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, 2008, 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, 2008 of the Company and our report dated March 4, 2009 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 the wholesale propane logistics business from the separate records maintained by DCP Midstream, LLC and (2) 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 4, 2009

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, 2008.

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 2008. In addition, directors are expected to be prepared for each meeting of the board by reviewing materials distributed in advance.

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
Thomas C. O’Connor	53	Chairman of the Board and Director
Mark A. Borer	54	President, Chief Executive Officer and Director
Angela A. Minas	44	Vice President and Chief Financial Officer
Michael S. Richards	49	Vice President, General Counsel and Secretary
Don Baldridge	39	Vice President, Business Development
Paul F. Ferguson, Jr.	59	Director
Gregory J. Goff	52	Director
Alan N. Harris	55	Director
John E. Lowe	50	Director
Frank A. McPherson	75	Director
Thomas C. Morris	68	Director
Stephen R. Springer	62	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.

Thomas C. O’Connor was elected Chairman of the Board of DCP Midstream GP, LLC in September 2008, and has been a director of DCP Midstream GP, LLC since 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.

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.

Angela A. Minas was elected Vice President and Chief Financial Officer of DCP Midstream GP, LLC in September 2008. Ms. Minas was previously Chief Financial Officer, Chief Accounting Officer and Treasurer for Constellation Energy Partners from September 2006 through March 2008. She also served as Managing Director of the Commodities Group at Constellation Energy Group, Inc. from September 2006 through March 2008. Prior to that, Ms. Minas was Senior Vice President, Global Consulting from 2004 to 2006 for SAIC and Vice President, US Consulting from 2002 to 2003 for SAIC. Prior to that, Ms. Minas was a partner with Arthur Andersen LLP from 1997 through 2002.

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.

Don Baldridge was elected Vice President, Business Development of DCP Midstream GP, LLC in January 2009. Mr. Baldridge was previously Vice President, Corporate Development of DCP Midstream, LLC since August 2008. Prior to that, he served as senior director, corporate development and other management positions with DCP Midstream, LLC since April 2005. Mr. Baldridge has more than 16 years experience in the energy industry, including commercial, trading and business development activities.

Paul F. Ferguson, Jr. was elected as a director of DCP Midstream GP, LLC in November 2005. Mr. Ferguson was a member of the Compensation, Audit and special committees of the general partner of TEPPCO Partners, L.P. 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. Mr. Ferguson was a director of the general partner of TEPPCO Partners, L.P. from October 2004 until his resignation in 2005.

Gregory J. Goff, was elected a director of DCP Midstream GP, LLC in October 2008, and is currently Senior Vice President, Commercial for ConocoPhillips. Previously, Mr. Goff served as President, Specialty Businesses and Business Development. From 2004 to 2006, Mr. Goff served as president of ConocoPhillips' US Lower 48 and Latin American exploration and production business. From 2002 to 2004 Mr. Goff served as president of Europe and Asia Pacific Downstream Activities for ConocoPhillips. From 2000 to 2002 Mr. Goff served as Chairman and Managing Director of Conoco Limited in the United Kingdom. From 1998 to 2000 Mr. Goff served as managing Director and Chief Executive Officer of Conoco JET Nordic in Stockholm, Sweden.

Alan N. Harris was appointed as a director of DCP Midstream GP, LLC in December 2008, effective January 1, 2009; at that time he was not appointed to any committee of the board of Directors. In January 2009, the board of directors appointed Mr. Harris as Chairman to the compensation committee of the board of directors. Mr. Harris currently serves as chief development and operations officer of Spectra Energy. Prior to Spectra Energy's spin-off from Duke Energy in 2007, Mr. Harris served as group vice president and chief financial officer of Duke Energy Gas Transmission, or DEGT, from February 2004 and was named executive vice president of DEGT in December 2002. Mr. Harris, who joined the corporation in 1982, has served in a number of other senior management positions since that time. Mr. Harris has been in the energy industry for over 30 years.

John E. Lowe, was elected a director of DCP Midstream GP, LLC in October 2008, and is currently Assistant to the Chief Executive Officer for ConocoPhillips, representing the company in external relationships and assisting on special projects. Mr. Lowe was previously Executive Vice President, Exploration and Production. Mr. Lowe has also served ConocoPhillips as Executive Vice President of Planning, Strategy and Corporate Affairs. Senior Vice President of Corporate Strategy and Development and was responsible for the forward strategy, development opportunities and public relations functions of Phillips Petroleum Company. From 1999 to 2000, Mr. Lowe served as Vice President of Planning and Strategic Transactions for ConocoPhillips.

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 previously served on the boards of Integris Health, Tri Continental Corporation, Seligman Group of Mutual Funds, ConocoPhillips, Kimberly Clark Corporation, MAPCO Inc., Bank of Oklahoma, the Federal Reserve Bank of Kansas City, the Oklahoma State University Foundation Board of Trustees, the American Petroleum Institute, and several non-profit organizations in Oklahoma.

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.

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, 2008, all Section 16(a) filing requirements applicable to such reporting persons were complied with, except that a late Form 4 was filed for Ms. Minas in January 2009 reflecting the granted phantom units dated October 1, 2008, following her employment by the Partnership.

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, Alan N. Harris (chairman), Gregory J. Goff, Thomas C. O'Connor and Frank A. McPherson. 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 March 26, 2008, Mark A. Borer, our Chief Executive Officer, certified to the NYSE, as required by NYSE rules, that as of March 26, 2008, 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, 2008, 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

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 February 23, 2009, our General Partner has four executive officers and six 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 February 23, 2009. 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;
- 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 2008 we engaged the services of BDO Seidman, LLP, 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 2008 Towers Perrin General Industry Executive Compensation Database, or the Towers Perrin Database. The study was comprised of the following peer 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, Spectra Energy Partners, LP, Sunoco Logistics Partners L.P., Targa Resources Partners LP and TEPPCO Partners LP. 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 2008, 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 a significant portion of the compensation of our executive officers should be performance-based since these individuals have a greater opportunity to influence 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 2008, 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 2008, 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 2008 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 2008 stated company objectives under the STI were based on the following and were weighted as indicated:

1) The achievement of our budget for operating cash flow from our 2008 budgeted asset base, excluding the impact from non-cash mark to market adjustments to derivative instruments and any one-time transaction costs. We define operating cash flow as our distributable cash flow plus maintenance capital and interest expense. As a publicly traded limited partnership, our performance is generally judged on our ability to pay cash distributions to our unitholders. Distributable cash flow has three primary components: maintenance capital, interest expense and operating cash flow. We use operating cash flow as the financial objective because we believe it is the most controllable component of distributable cash flow and permits management to focus on the long term sustainability and development of our assets. For this company objective, the target level of performance is operating cash flow of $118.0 million, the maximum level of performance is operating cash flow of $135.0 million and the minimum level of performance operating cash flow of $110.0 million. The weighting of this objective relative to the other stated company objectives was 35%.

2) Deliver on board approved 2008 growth capital including acquisitions, organic growth projects and the dropdown of assets from our sponsors. We believe that our performance is also judged by our growth, which can translate into distribution growth. For this company objective, the target level of performance is $400.0 million of approved growth capital in 2008, the maximum level of performance is $900.0 million of approved growth capital in 2008 and the minimum level of performance is $250.0 million of approved growth capital in 2008. The weighting of this objective relative to the other stated company objectives was 25%.

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 minimum level of performance will be based on having no material weaknesses identified by management or the external auditor. A subjective determination will be made by the Audit Committee to assess performance between the minimum and maximum level of performance taking into consideration the number of significant deficiencies identified. The weighting of this objective relative to the other stated company objectives was 7%.

4) A safety objective based on recordable incident rate, or RIR, of both our assets and the assets of DCP Midstream, LLC, the owner of our general partner and the operator or our assets. If a fatality occurs of our employee or that of our contractor on our premises, a 5% safety penalty will be assessed against the entire STI payout. For this company objective, the target level of performance is an RIR of 0.75, the maximum level of performance is an RIR of 0.40 and the minimum level of performance is an RIR of 0.95. The weighting of this objective relative to the other stated company objectives was 5%.

5) An environmental objective of non-routine air emissions, natural gas vented or flared, of both our assets and the assets of DCP Midstream, LLC. For this company objective, the target level of

performance is 1,000 million standard cubic feet, or MMscf, the maximum level of performance is 790 MMscf and the minimum level of performance is 1,200 MMscf. The weighting of this objective relative to the other stated company objectives was 3%.

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. The level of performance achieved for each objective was as follows:

STI Objective	Level of Performance Achieved
1) Operating cash flow	Between Minimum and Target
2) Growth capital	Between Minimum and Target
3) Internal controls	Target
4) Safety	Between Minimum and Target
5) Environmental	Below Minimum — No Payout

For fiscal year 2008, the compensation committee and the board of directors adjusted the actual payout on the company objectives downward to 50% of target. In making this adjustment, we considered the current economic challenges created by the U.S. and global recession, the performance of the Partnership's publicly traded equity and the operational challenges that were encountered by the Partnership in 2008. Taking all of these factors into consideration, we felt that it was prudent to reduce the annual cash incentives of management for these company objectives. As a result of this adjustment, the aggregate level of payout achieved for the above company objectives will be 50% of target.

The 2008 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, 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 2008, the compensation committee and the board of directors adjusted downward the actual payout on these personal objectives as a result of the U.S. and global recessions, the performance of the Partnership's publicly traded equity and the operational challenges that were encountered by the Partnership in 2008. As a result of these adjustments, the aggregate level of payout achieved by the executive officers as a group on their personal objectives will be 54.5% of target.

As a result of the adjustments recommended by the compensation committee and ratified by the board of directors discussed above regarding the company objectives and the personal objectives, the total payout for the executive officers under the STI for fiscal year 2008 ranged from 37.5% to 65.5% of target, with the CEO at 37.5%.

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 issued phantom limited partner units to each executive officer. Half of such phantom units are performance phantom units, or PPUs, and half are restricted phantom units, or RPUs. The PPUs will vest based upon the level of achievement of certain performance objectives over a three year performance period, or the Performance Period. The RPUs will automatically vest if the executive officer remains employed with us at the end of a three year vesting period, or the Vesting Period. We believe this program promotes retention of our executive officers, and focuses our executive officers on the goal of long-term value creation.

For 2008, the PPUs have as a performance measurement total shareholder return over the Performance Period relative to a peer group of 31 other similar public limited partnerships that we believe that we compete with in the capital markets. The companies included in this peer group at the start of 2008 were the following: Atlas Pipeline Partners LP, Boardwalk Pipeline Partners LP, Buckeye Partners L P, Copano Energy, L.L.C., Crosstex Energy LP, Duncan Energy Partners L.P., Eagle Rock Energy Partners L P, El Paso Pipeline Partners, L.P., Enbridge Energy Partners LP, Energy Transfer Partners, L.P., Enterprise Products Partners L P, Genesis Energy LP, Global Partners LP, Hiland Partners, LP, Holly Energy Partners LP, Kinder Morgan Energy Partners LP, Magellan Midstream Partners LP, MarkWest Energy Partners LP, NuStar Energy L.P., ONEOK Partners LP, Plains All American Pipeline LP, Quicksilver Gas Services LP, Regency Energy Partners LP, Semgroup Energy Partners, L.P., Spectra Energy Partners, LP, Sunoco Logistics Partners LP, Targa Resources Partners LP, TC Pipelines LP, TEPPCO Partners LP, TransMontaigne Partners L.P. and Williams Partners L.P. If a company originally named to the peer group is not publicly traded at the end of the Performance Period, none of its performance will be used in calculating the peer group's total shareholder return. If there is a combination of any peer group companies during the Performance Period, the performance of the surviving entity will be used. No new companies will be added to the peer group during the Performance Period.

For 2008, the RPUs will vest automatically at the end of the Vesting Period provided the executive officer remains employed with us at the end of such period.

These PPU and RPU awards were granted at the first regular board of directors' meeting during the first quarter of 2008. 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 dividend equivalent rights, or DERs, on the number of units earned during the Vesting Period. The DERs on the PPUs will be paid in cash at the end of the Performance Period and the DERs on the RPUs will be paid quarterly in cash during the Vesting Period. The amount paid on the DERs will equal the quarterly distributions actually paid during the Performance Period and the Vesting Period on the number of PPUs or RPUs earned.

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 PPUs and RPUs 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 2008 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.

For the PPUs granted in 2008, the performance measure is total shareholder return over the Performance Period relative to the peer group described above. 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. The compensation committee believes utilizing total shareholder return as a performance measure provides incentive for the continued growth of our operating footprint and distributions to unitholders. This performance measure, coupled with the 2008 STI objectives to meet or exceed operating cash flow targets, provides management with appropriate incentives for our disciplined and steady growth. If our total shareholder return ranking among the 31 companies listed in our peer group over the Performance Period is less than the 30th percentile, 0% of the PPUs will vest. If such ranking over the Performance Period is in the 30th percentile, 50% percent of the PPUs will vest. If such ranking over the Performance Period is in the 50th percentile, 100% of the PPUs will vest and if such ranking over the Performance Period is in the 90th percentile, 200% of the PPUs will vest. Total shareholder return will be based on data obtained from Bloomberg and assumes that any dividends or distributions are reinvested.

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 PPUs, RPUs and related DERs will (i) be replaced with equivalent units of the new enterprise if there is no change in the recipient's job status for twelve months or (ii) fully vest if the recipient is severed or if the recipient's job is lower in status within twelve months of the change in control.

In the event an award recipient's employment is terminated after the first anniversary of the grant date 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's (i) performance units will contingently vest on a pro-rata basis for time worked over the Performance Period and final performance, measured at the end of the Performance Period, will determine the payout and (ii) time vested units will become fully vested and payable. 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:

Phantom IPO Units — In conjunction with our initial public offering, in January 2006 our General Partner's board of directors granted phantom limited partnership units, or Phantom IPO Units, to key employees, including the executive officers. These Phantom IPO Units vested in January 2009 and were paid in common units. There was no performance condition associated with these Phantom IPO Units. Award recipients also received DERs based on the number of common units awarded, which were paid in cash on a quarterly basis from the date of the initial grant. These phantom IPO units 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.

Company Matching and Retirement Contributions to Defined Contribution Plans — 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. We have no defined benefit plans.

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 nonqualified, defined contribution 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 13% 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, 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 physical exam expenses. Finally, we provide all our employees with a monthly parking pass or a pass to be used on available public transportation systems.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code § 162(m). Accordingly, none of the compensation paid to our named executive officers is subject to the limitation.

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 from the date the executive officer commences employment with us. Ownership is reported annually to the compensation committee. As of December 31, 2008, 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 Group Vice President and Chief Administrative Officer of DCP Midstream, LLC. In addition, the compensation committee engaged the services of BDO Seidman, LLP, and 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, 2008.

Compensation Committee

Alan N. Harris (Chairman)
Gregory J. Goff
Frank A. McPherson
Thomas C. O’Connor

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	Year	Salary	LTIP Awards(e)	Non-Equity Incentive Plan Compensation	Change in Nonqualified Deferred Compensation Earnings(f)	All Other Compensation(g)	Total
Mark A. Borer(a)	2008	$358,538	$ (34,138)	$ 80,671	$ 56,236	$126,851	$ 588,158
President and Chief	2007	$341,000	$ 151,763	$331,043	$ 36,518	$ 80,908	$ 941,232
Executive Officer	2006	$ 47,215	$ —	$ 46,655	$ 45	$ 2,052	$ 95,967
Angela A. Minas(b)	2008	$ 61,923	$ 3,541	$ 18,252	$ —	$ 49,199	$ 132,915
Vice President and Chief Financial Officer							
Thomas E. Long(c)	2008	$ 76,168	$(396,593)	$ —	$(61,564)	$ 31,955	$(350,034)
Vice President and	2007	$199,212	$ 304,402	$145,605	$ 1,584	$ 54,268	$ 705,071
Chief Financial Officer	2006	$180,000	$ 92,191	$133,650	$ —	$ 33,182	$ 439,023
Michael S. Richards	2008	$181,748	$(232,166)	$ 52,343	$ (6,765)	$ 65,136	$ 60,296
Vice President, General	2007	$172,615	$ 282,729	$125,903	$ 48	$ 46,431	$ 627,726
Counsel and Secretary	2006	$165,000	$ 88,390	$122,048	$ —	$ 32,717	$ 408,155
Greg K. Smith(d)	2008	$190,970	$(236,289)	$ 32,226	$ (4,248)	$ 69,620	$ 52,279
Vice President, Business	2007	$179,644	$ 289,184	$131,080	$ 866	$ 51,185	$ 651,959
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) Ms. Minas' employment with the General Partner commenced effective September 8, 2008.

(c) Mr. Long's employment with the General Partner terminated effective April 30, 2008.

(d) Mr. Smith's employment with the General Partner terminated effective January 5, 2009, and he commenced employment with DCP Midstream, LLC. Mr. Smith has been replaced by Don Baldridge, formerly employed by DCP Midstream, LLC.

(e) The amounts in this column reflect the dollar amount recognized for financial statement reporting purposes in accordance with the provisions of Statement of Financial Accounting Standard No. 123(R), Share-Based Payment, or SFAS 123R, which incorporates re-measurement of awards for changes in the underlying assumptions used in prior periods, such as the unit price at the measurement date and the performance measure percentage. These amounts reflect our accounting expense and may not necessarily correspond to the actual value that will be realized by the named executives. The amounts exclude the impact of an estimated forfeiture rate under SFAS 123R, but do include the impact of forfeited awards if any of the named executives fail to perform the requisite service. Accordingly, the amounts may be negative due to these factors. This column reflects awards granted in January 2006 related to our initial public offering, and awards granted in conjunction with our LTIP. See Note 14 of the Notes to Consolidated Financial Statements in Item 8, "Financial Statements and Supplementary Data."

(f) Amounts in this column are also included in the "Nonqualified Deferred Compensation" table below.

(g) 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 $365,000 for 2008 and $341,000 for both 2007 and 2006, of which he deferred $125,488, $120,391 and $8,944 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Borer's target opportunity was 60% of his annual base salary, with the possibility of earning from 0 to 120% of his annual base salary in 2008, and 0% to 109% of his annual base salary in 2007 and 2006, 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:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 29,900	$ 29,950	$ —
Nonqualified deferred compensation program contributions	$ 50,160	$ 32,063	$ 1,945
DERs	$ 44,947	$ 18,370	$ —
Life insurance premiums(a)	$ 1,844	$ 1,225	$ 107

(a) Paid by the Partnership on behalf of Mr. Borer.

Angela A. Minas, Vice President and CFO

The annual base salary for Ms. Minas was $230,000 for 2008, of which she deferred $0 in 2008. The LTIP awards are comprised of PPUs and RPUs pursuant to the LTIP. Under the 2008 STI, Ms. Minas' target opportunity was 45% of her annual base salary, with the possibility of earning from 0% to 90% of her annual base salary, depending on the level of performance in each of the STI objectives, which was pro rated in 2008 based upon her service period in 2008.

“All Other Compensation” includes the following:

	2008
Relocation expenses	$ 41,901
Company retirement contributions to defined contribution plans	$ 5,131
DERs	$ 2,034
Life insurance premiums(a)	$ 133

(a) Paid by the Partnership on behalf of Ms. Minas.

Thomas E. Long, former Vice President and CFO

The annual base salary for Mr. Long was $215,000, $199,980 and $180,000 for 2008, 2007 and 2006, respectively, of which he deferred $131,070, $89,645 and $0 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Long’s target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

“All Other Compensation” includes the following:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 11,795	$ 28,476	$ 21,553
Nonqualified deferred compensation program contributions	$ 14,796	$ —	$ —
DERs	$ 5,324	$ 25,075	$ 10,981
Life insurance premiums(a)	$ 40	$ 717	$ 648

(a) 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 $185,000, $172,920 and $165,000 for 2008, 2007 and 2006, respectively, of which he deferred $15,397, $3,452 and $0 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under both the 2008 and 2007 STI, Mr. Richards’ target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

“All Other Compensation” includes the following:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 23,000	$ 22,500	$ 20,891
Nonqualified deferred compensation program contributions	$ 6,550	$ —	$ —
DERs	$ 35,020	$ 23,309	$ 10,482
Life insurance premiums(a)	$ 566	$ 622	$ 594
Deminimus bonus	$ —	$ —	$ 750

(a) Paid by the Partnership on behalf of Mr. Richards.

Greg K. Smith, former Vice President, Business Development

The annual base salary for Mr. Smith was $195,000, $180,030 and $170,000 for 2008, 2007 and 2006, respectively, of which he deferred $7,638, $7,186 and $6,800 in 2008, 2007 and 2006, respectively. The LTIP awards are comprised of Phantom IPO Units, PPUs and RPUs pursuant to the LTIP. Under the 2008, 2007 and 2006 STI, Mr. Smith’s target opportunity was 45% of his annual base salary, with the possibility of earning from 0% to 90% of his annual base salary in 2008, and 0% to 82% of his annual base salary in 2007 and 2006, depending on the level of performance in each of the STI objectives.

"All Other Compensation" includes the following:

	2008	2007	2006
Company retirement contributions to defined contribution plans	$ 23,926	$ 23,855	$ 21,928
Nonqualified deferred compensation program contributions	$ 9,265	$ 2,864	$ 2,864
DERs	$ 36,030	$ 23,818	$ 10,640
Life insurance premiums(a)	$ 399	$ 648	$ 612

(a) Paid by the Partnership on behalf of Mr. Smith.

Grants of Plan-Based Awards

Following are the grants of plan-based awards during the year ended December 31, 2008 for the General Partner's executive officers:

		Estimated Future Payouts under Non-Equity Incentive Plan Awards (a)			Estimated Future Payouts under Equity Incentive Plan Awards			Grant Date Fair Value of LTIP Awards
Name	Grant Date	Minimum ($)	Target ($)	Maximum ($)	Minimum (#)	Target (#)	Maximum (#)	($)
Mark A. Borer	NA	$ 109,500	$ 219,000	$ 438,000	—	—	—	$ —
PPUs	2/25/2008(b)	$ —	$ —	$ —	3,305	6,610	9,915	$ 237,167
RPUs	2/25/2008(c)	$ —	$ —	$ —	6,610	6,610	6,610	$ 237,167
Angela A. Minas	NA	$ 51,750	$ 103,500	$ 207,000	—	—	—	$ —
PPUs	2/25/2008(b)	$ —	$ —	$ —	848	1,695	2,543	$ 28,273
RPUs	2/25/2008(c)	$ —	$ —	$ —	1,695	1,695	1,695	$ 28,273
Michael S. Richards	NA	$ 41,625	$ 83,250	$ 166,500	—	—	—	$ —
PPUs	2/25/2008(b)	$ —	$ —	$ —	1,030	2,060	3,090	$ 73,913
RPUs	2/25/2008(c)	$ —	$ —	$ —	2,060	2,060	2,060	$ 73,913
Greg K. Smith	NA	$ 43,875	$ 87,750	$ 175,500	—	—	—	$ —
PPUs	2/25/2008(b)	$ —	$ —	$ —	1,088	2,175	3,263	$ 78,039
RPUs	2/25/2008(c)	$ —	$ —	$ —	2,175	2,175	2,175	$ 78,039

(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 represents units awarded under the LTIP. If minimum levels of performance are not met, then the payout may be zero.

(c) The number of units shown represents units awarded under the LTIP and these units vest at the end of the Vesting Period provided the individual is still employed by the Partnership.

The PPUs awarded on February 25, 2008 will vest in their entirety on December 31, 2010 if the specified performance conditions are satisfied and the RPUs awarded on February 25, 2008 will vest in their entirety on December 31, 2010 if the executive is still employed by the Partnership.

Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the General Partner's executive officers as of December 31, 2008:

	Outstanding LTIP Awards			
Name	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	—	$ —	25,110	$ 238,269
Angela A. Minas	—	$ —	3,390	$ 31,866
Michael S. Richards	4,000	$ 37,600	12,730	$ 138,968
Greg K. Smith	4,000	$ 37,600	13,250	$ 144,416

(a) Phantom IPO Units awarded 1/3/2006; units vest in their entirety on 1/3/2009. For additional information, see "Compensation Discussion and Analysis — Other Compensation — Phantom IPO Units."

(b) Value calculated based on the closing price of our common units at December 31, 2008.

(c) PPUs and RPUs awarded 5/5/2006, 2/26/2007 and 2/25/2008; units vest in their entirety over a range of 0% to 150% on 12/31/2008, 12/31/2009 and 12/31/2010, respectively, if the specified performance conditions are satisfied, except that the RPUs vest in their entirety on 12/31/2010; to determine the market value, the calculation of the number of units that are expected to vest for units granted in 2008 is based on assumed performance at 100%, for units granted in 2007 is based on assumed performance at 102%, and for units granted in 2006 is based on actual performance at 140.4%.

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, 2008.

Nonqualified Deferred Compensation

Following is the nonqualified deferred compensation for the General Partner's executive officers for the year ended December 31, 2008:

Name	Executive Contributions in Last Fiscal Year(a)	Registrant Contributions in Last Fiscal Year(b)	Aggregate Earnings (Losses) in Last Fiscal Year(c)	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2008
Mark A. Borer	$ 125,488	$ 50,160	$ 56,236	$ —	$ 901,245
Thomas E. Long	$ 131,070	$ 14,796	$ (61,564)	$ (27,339)	$ 148,337
Angela A. Minas	$ —	$ —	$ —	$ —	$ —
Michael S. Richards	$ 15,397	$ 6,550	$ (6,765)	$ —	$ 18,708
Greg K. Smith	$ 7,638	$ 9,265	$ (4,248)	$ —	$ 44,305

(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."

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 — Effective February 17, 2009, 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 Phantom Units that approximate $40,000 of value, awarded pursuant to the LTIP, 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 Units 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.

Following is the compensation of the General Partner's Non-Employee Directors for the year ended December 31, 2008:

Name	Fees Earned	LTIP Awards(a)	DERs	Total
Paul F. Ferguson, Jr.	$ 90,000	$ 5,479	$ 2,762	$ 98,241
Frank A. McPherson	$ 72,500	$ 5,479	$ 2,762	$ 80,741
Thomas C. Morris	$ 69,000	$ 5,479	$ 2,762	$ 77,241
Stephen R. Springer	$ 89,500	$ 24,774	$ 1,475	$ 115,749

(a) 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. See Note 14 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Mr. Ferguson is the audit committee chair and a member of the special committee.

Mr. McPherson was the special committee chair until February 2008, 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.

The total aggregate grant date fair value of LTIP awards for the Non-Employee Directors for 2008 was $143,520. At December 31, 2008, Messrs. Ferguson, McPherson and Morris each had 666 Phantom IPO Units outstanding, which vested on January 3, 2009 and were paid in common units.

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 February 23, 2009;
- 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 units beneficially owned is based on 28,233,183 common units outstanding.

Name of Beneficial Owner(a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
DCP LP Holdings, LP(b)(1)	8,246,451	29.2%
Kayne Anderson Capital Advisors, L.P.(c)	1,778,335	6.3%
Barclays PLC(d)	1,666,334	5.9%
Mark A. Borer	38,001	*
Angela A. Minas	15,000	*
Michael S. Richards	12,101	*
Don Baldridge	6,101	*
Alan N. Harris	9,842	*
Paul F. Ferguson, Jr.	6,334	*
John E. Lowe	40,001	*
Frank A. McPherson	15,666	*
Thomas C. Morris	20,667	*
Thomas C. O’Connor	8,000	*
Stephen R. Springer	1,500	*
All directors and executive officers as a group (11 persons)	173,213	*

* 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 February 17, 2009. The address of Kayne Anderson Capital Advisors, L.P. is 1800 Avenue of the Stars, Second Floor, Los Angeles, CA 90067.

(d) As set forth in a Schedule 13G filed on September 22, 2008. The address of Barclays PLC is 1 Churchill Place, London, E14 5HP, England.

Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2008.

	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	—	—	769,592
Total	—	$ —	769,592

(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. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.
Payments to our General Partner and its affiliates	We reimburse DCP Midstream, LLC and its affiliates $10.1 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. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition of Michigan Pipeline & Processing, LLC, or MPP. 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 2009 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
Momentum Energy Group, Inc.	August 2007	1.6
Michigan Pipeline & Processing, LLC	October 2008	0.4
Total		$ 10.1

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 derivative 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

DCP Midstream, LLC agreed to indemnify us for up to $5.3 million of our pro rata share of any capital contributions associated with repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC 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 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 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.

We have not pursued indemnification under these agreements.

Contracts with Affiliates

We charge transportation fees, sell a portion of our residue gas and NGLs to, and purchase natural gas and NGLs from, DCP Midstream, LLC, ConocoPhillips, and their respective affiliates. We also purchase a portion of our propane from and market propane on behalf of Spectra Energy. Management anticipates continuing to purchase and sell these commodities to DCP Midstream, LLC, ConocoPhillips and their respective affiliates, and Spectra Energy 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 180 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."

Propane Supply Arrangements

During the second quarter of 2008, we entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides us propane supply at our marine terminal, which is included in our Wholesale Propane Logistics segment, for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated for non-performance during the first quarter of 2008.

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 $3.8 million and $0.3 million during 2008 and 2007, respectively, to reimburse us for these capital projects, which were substantially completed in 2008.

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, 2008	Year Ended December 31, 2007
	(Millions)	
Audit Fees(a)	$ 1.6	$ 1.9

(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.

For the last two fiscal years, Deloitte has not billed us for assurance and related services, unless such services were reasonably related to the performance of the audit or review of our financial statements, and are included in the table above. Deloitte has not provided any services to us over the last two fiscal years related to tax compliance, tax services and tax planning.

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.

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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, 2008						
Allowance for doubtful accounts	$ 1.2	$ (0.5)	$ —	$ (0.1)	$ —	$ 0.6
Environmental	1.7	0.5	—	(0.3)	—	1.9
Other(b)	—	2.6	—	—	—	2.6
	$ 2.9	$ 2.6	$ —	$ (0.4)	$ —	$ 5.1
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

(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***

Table of Contents

Discovery Producer Services LLC

Consolidated Financial Statements

For the Years Ended December 31, 2008, 2007 and 2006

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, 2008 and 2007, and the related consolidated statements of income, members' capital, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst &Young LLP

Tulsa, Oklahoma
February 23, 2009

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 42,052	$ 38,509
Trade accounts receivable:		
Affiliate	202	22,467
Other	1,899	5,847
Insurance receivable	3,373	5,692
Inventory	519	483
Other current assets	2,933	5,037
Total current assets	50,978	78,035
Restricted cash	3,470	6,222
Property, plant, and equipment, net	370,482	368,228
Total assets	$ 424,930	$ 452,485
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities:		
Accounts payable:		
Affiliate	$ 3,125	$ 8,106
Other	34,779	17,617
Accrued liabilities	5,714	6,439
Other current liabilities	1,616	1,658
Total current liabilities	45,234	33,820
Noncurrent accrued liabilities	19,771	12,216
Members' capital	359,925	406,449
Total liabilities and members' capital	$ 424,930	$ 452,485

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Revenues:			
Product sales:			
Affiliate	$ 207,706	$ 216,889	$ 148,385
Third-party	1,324	5,251	—
Gas and condensate transportation services:			
Affiliate	782	979	3,835
Third-party	13,308	15,553	14,668
Gathering and processing services:			
Affiliate	1,506	3,092	8,605
Third-party	12,709	17,767	19,473
Other revenues	3,913	1,141	2,347
Total revenues	241,248	260,672	197,313
Costs and expenses:			
Product cost and shrink replacement:			
Affiliate	83,576	93,722	66,890
Third-party	63,422	61,982	52,662
Operating and maintenance expenses:			
Affiliate	8,836	5,579	5,276
Third-party	27,834	23,409	17,773
Depreciation and accretion	21,324	25,952	25,562
Taxes other than income	1,439	1,330	1,114
General and administrative expenses — affiliate	4,500	2,280	2,150
Other (income) expense, net	(3,511)	534	283
Total costs and expenses	207,420	214,788	171,710
Operating income	33,828	45,884	25,603
Interest income	(650)	(1,799)	(2,404)
Foreign exchange (gain) loss	78	(388)	(2,076)
Net income	$ 34,400	$ 48,071	$ 30,083

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	Total
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
Contributions	—	5,700	7,376	13,076
Distributions	—	(56,400)	(37,600)	(94,000)
Net income	—	20,641	13,759	34,400
Balance at December 31, 2008	$ —	$ 214,871	$ 145,054	$ 359,925

See accompanying notes to consolidated financial statements.

DISCOVERY PRODUCER SERVICES LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
OPERATING ACTIVITIES:			
Net income	$ 34,400	$ 48,071	$ 30,083
Adjustments to reconcile to cash provided by operations:			
Depreciation and accretion	21,324	25,952	25,562
Net loss on disposal of equipment	175	603	—
Cash provided (used) by changes in assets and liabilities:			
Trade accounts receivable	26,213	(9,389)	26,599
Insurance receivable	2,319	6,931	(12,147)
Inventory	(36)	93	348
Other current assets	2,104	(802)	(1,911)
Accounts payable	5,932	(7,540)	(6,062)
Accrued liabilities	(725)	1,320	(1,086)
Other current liabilities	(52)	(3,147)	2,070
Net cash provided by operating activities	91,654	62,092	63,456
INVESTING ACTIVITIES:			
Decrease in restricted cash	2,752	22,551	15,786
Property, plant, and equipment:			
Capital expenditures	(16,188)	(31,739)	(33,516)
Proceeds from sale of property, plant and equipment	—	649	—
Change in accounts payable — capital expenditures	6,249	2,625	568
Net cash used by investing activities	(7,187)	(5,914)	(17,162)
FINANCING ACTIVITIES:			
Distributions to members	(94,000)	(59,172)	(43,598)
Capital contributions	13,076	3,920	13,509
Net cash used by financing activities	(80,924)	(55,252)	(30,089)
Increase in cash and cash equivalents	3,543	926	16,205
Cash and cash equivalents at beginning of period	38,509	37,583	21,378
Cash and cash equivalents at end of period	$ 42,052	$ 38,509	$ 37,583

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 (DPS) a Delaware limited liability company formed on June 24, 1996, and its wholly owned subsidiary, Discovery Gas Transmission LLC (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 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 mainline has a design capacity of 600 MMcf/d and consists of approximately 105 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".

At the beginning of the periods presented, we were owned 20% by Williams Energy, L.L.C. (a wholly owned subsidiary of The Williams Companies, Inc.), 40% by DCP Assets, LP (DCP) and 40% by Williams Partners Operating LLC (a wholly owned subsidiary of Williams Partners L.P) (WPZ). Williams Energy, L.L.C. is our operator. Herein, The Williams Companies, Inc. and its subsidiaries are collectively referred to as "Williams."

On June 28, 2007, WPZ acquired the 20% interest in us previously held by Williams Energy, L.L.C. Hence, 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.

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. The cash and cash equivalent balance is primarily invested in funds with high-quality, short term securities and instruments that are issued or guaranteed by the U.S. government. These securities have 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. We do not recognize an allowance for doubtful accounts 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, 2008 and 2007.

Insurance Receivable. Hurricane Katrina damaged our pipeline and onshore facilities in 2005, and Hurricane Ike damaged the 30" mainline and 18" lateral in 2008. Expenditures incurred for the repair of these damages which are probable for recovery when incurred are recorded as insurance receivable. We expense expenditures up to the insurance deductible ($6.4 million in 2008), amounts not covered by insurance ($2.0 million in 2008) and amounts subsequently determined not to be recoverable.

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 weighted average 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. Pursuant to a settlement with our shippers issued by the Federal Energy Regulatory Commission on February 5, 2008, if a cash-out refund is due and payable to a shipper during any year pursuant to Transporter's FERC Gas Tariff, shipper will be deemed to have immediately assigned its right to the refund amount to us.

Inventory. Inventory includes fractionated products at our Paradis facility and is carried at the lower of cost or market. Cost is determined based on the weighted average natural gas shrink replacement cost.

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 is recorded 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 property, plant and equipment is provided on a straight-line basis over the estimated useful lives of 25 to 35 years. Expenditures for maintenance and repairs are expensed as incurred. Expenditures that extend the useful lives of the assets or increase their functionality are capitalized. The cost of property, plant and equipment sold or retired and the related accumulated depreciation is removed from the accounts in the period of sale or disposition. Gains and losses on the disposal of property, plant and equipment are recorded in the Statements of Income.

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 corresponding accretion expense included in operating income.

Revenue Recognition. Revenue for sales of products is 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 its and other third parties regulatory proceedings, advice of counsel, estimated total exposure as discounted and risk weighted, and collection and other risks. There were no rate refund liabilities accrued at December 31, 2008 or 2007.

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.

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.

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 and
- processing and sales of natural gas liquids and transportation of gas and condensate for DCP's affiliates, Texas Eastern Corporation and ConocoPhillips Company.

The following table summarizes these related-party revenues during 2008, 2007 and 2006.

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Williams	$ 207,782	$ 217,012	$ 148,543
Texas Eastern Corporation	1,953	3,912	12,282
ConocoPhillips	259	36	—
Total	$ 209,994	$ 220,960	$ 160,825

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 under a 10-year leasing agreement for pipeline capacity through 2015 from Texas Eastern Transmission, LP (an affiliate of DCP)

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, 2008	2007	2006
	(In thousands)		
Capitalized labor	$ 317	$ 222	$ 373
Capitalized project fee	375	651	538
	$ 692	$ 873	$ 911

Note 4. Property, Plant, and Equipment

Property, plant, and equipment consisted of the following at December 31, 2008 and 2007:

	Years Ended December 31, 2008	2007	Estimated Depreciable Lives
	(In thousands)		
Property, plant, and equipment:			
Construction work in progress	$ 76,302	$ 66,550	
Buildings	5,054	4,950	25 — 35 years
Land and land rights	5,575	2,491	0 — 35 years
Transportation lines	305,172	311,368	25 — 35 years
Plant and other equipment	216,189	200,722	25 — 35 years
Total property, plant, and equipment	608,292	586,081	
Less accumulated depreciation	237,810	217,853	
Net property, plant, and equipment	$ 370,482	$ 368,228	

Effective July 1, 2008, we revised our estimate of the useful lives of the Larose processing plant and the regulated pipeline and gathering system. The annual depreciation expense will decrease $13 million.

Commitments for construction and acquisition of property, plant, and equipment for the Tahiti pipeline lateral expansion are approximately $1.5 million at December 31, 2008.

Our asset retirement 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 2008 and 2007 is presented below.

	Years Ended December 31, 2008	2007
	(In thousands)	
Balance at January 1	$ 12,118	$ 3,728
Accretion expense	1,082	422
Estimate revisions	3,327	7,554
Liabilities incurred	3,157	414
Balance at December 31	$ 19,684	$ 12,118

Note 5. Leasing Activities

We lease the land on which the Paradis fractionator 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 also have a ten-year leasing agreement for pipeline capacity from Texas Eastern Transmission, LP that includes renewal options and options to increase capacity which would also increase rentals. On September 12, 2008, we filed an amendment to the capacity lease agreement increasing the leased capacity and resulting in a lease payment increase of $380,000 annually. The future minimum annual rentals under these non-cancelable leases as of December 31, 2008 are payable as follows:

	(In thousands)
2009	$ 1,241
2010	1,241
2011	1,241
2012	1,241
2013	1,241
Thereafter	2,105
	$ 8,310

Total rent expense for 2008, 2007 and 2006, including a cancelable platform space lease and month-to-month leases, was $1.6 million, $1.4 million and $1.4 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.

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 42,052	$ 42,052	$ 38,509	$ 38,509
Restricted cash	3,470	3,470	6,222	6,222

Concentrations of Credit Risk

Our cash equivalent balance is primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

At December 31, 2008, substantially all of our customer accounts receivable result from gas transmission services provided for our largest three 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 2008 and 2007.

Major Customers. Williams accounted for approximately $208.0 million (86%), $217.0 million (83%), $149.8 million (75%) respectively, of our total revenues in 2008, 2007 and 2006. These revenues were for the sale of NGLs received as compensation under processing contracts with third-party producers.

Note 7. Rate and Regulatory Matters

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 30, 2008, DGT filed to maintain a lost-and-unaccounted-for percentage of zero percent until July 1, 2009 and to retain the 2007 net system gains of $2.3 million that are unrelated to the lost-and-unaccounted-for gas over recovered from its shippers. By Order dated June 26, 2008 the filing was approved. The approval was subject to a 30-day protest period, which passed without protest. As of December 31, 2008, and 2007, DGT has deferred amounts of $5.5 million and $5.8 million, respectively, included in current accrued liabilities in the accompanying Consolidated Balance Sheets. The December 31, 2008 balance includes 2008 unrecognized net system gains. The December 31, 2007 balance represents amounts collected from customers pursuant to prior years' lost and unaccounted for gas percentage and unrecognized net system gains.

On October 16, 2008, the FERC issued Order No. 717, implementing standards of conduct for interstate pipelines and marketing function employees of the interstate pipeline or of the pipeline's affiliates. The standards of conduct preclude an interstate pipeline from any actions that might provide any of its or its affiliate's marketing function employees with an unfair market advantage. The 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's pipeline; therefore, the standards of conduct are not currently applicable to DGT.

On November 16, 2007, DGT filed a petition for approval of a settlement in lieu of a general rate change filing with FERC. One shipper, ExxonMobil Gas & Power Marketing Company, filed a protest. 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 settlement allowed Discovery to recognize the amounts collected from customers pursuant to prior years lost and unaccounted for gas of $3.5 million. The order is now final and no longer subject to rehearing. DGT implemented the settlement rates and surcharges effective January 1, 2008.

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 material 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.

DCP East Texas Holdings, LLC

Consolidated Financial Statements

For the Years Ended

December 31, 2008, 2007 and 2006

Deloitte.

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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 Holdings, LLC (the "Company"), as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As described in Note 1 to the consolidated financial statements, through July 1, 2007, 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 4, 2009

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED BALANCE SHEETS
(millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13.9	$ 4.8
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $0.4 million and $0.5 million, respectively	14.1	16.0
Affiliates	20.7	64.5
Other	1.1	0.8
Other	0.4	0.4
Total current assets	50.2	86.5
Property, plant and equipment, net	253.4	236.5
Total assets	$ 303.6	$ 323.0
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 25.8	$ 53.6
Affiliates	2.4	1.5
Other	0.9	2.9
Operating accrual	1.8	1.3
Capital spending accrual	5.1	2.7
Other	2.4	3.7
Total current liabilities	38.4	65.7
Deferred income taxes	1.7	1.7
Other long-term liabilities	0.6	0.5
Total liabilities	40.7	67.9
Commitments and contingent liabilities		
Partners' equity	262.9	255.1
Total liabilities and partners' equity	$ 303.6	$ 323.0

See Notes to Consolidated Financial Statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS
(millions)

	Years Ended December 31,		
	2008	2007	2006
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 202.8	$ 179.8	$ 177.7
Sales of natural gas, NGLs and condensate to affiliates	313.7	270.9	286.6
Transportation and processing services	28.7	22.2	21.9
Transportation and processing services to affiliates	0.2	0.1	0.3
Losses from non-trading derivative activity — affiliates	(0.6)	(0.1)	(1.1)
Total operating revenues	544.8	472.9	485.4
Operating costs and expenses:			
Purchases of natural gas and NGLs	419.7	357.8	376.0
Purchases of natural gas and NGLs from affiliates	0.1	1.1	9.3
Operating and maintenance expense	34.5	27.2	24.4
Depreciation expense	16.7	15.8	14.6
General and administrative expense	0.7	1.8	0.2
General and administrative expense — affiliate	8.5	10.3	11.3
Total operating costs and expenses	480.2	414.0	435.8
Operating income	64.6	58.9	49.6
Interest income	0.4	0.3	—
Income before income taxes	65.0	59.2	49.6
Income tax expense	0.5	0.7	1.8
Net income	$ 64.5	$ 58.5	$ 47.8

See Notes to Consolidated Financial Statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY
(millions)

Balance, January 1, 2006	$ 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
Contributions	29.5
Distributions	(86.2)
Net income	64.5
Balance, December 31, 2008	$ 262.9

See Notes to Consolidated Financial Statements.

DCP EAST TEXAS HOLDINGS, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Year Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 64.5	$ 58.5	$ 47.8
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation expense	16.7	15.8	14.6
Deferred income taxes	(0.1)	(0.1)	1.8
Other, net	(0.1)	(0.1)	0.1
Change in operating assets and liabilities which provided (used) cash:			
Accounts receivable	45.9	(50.6)	0.3
Accounts payable	(28.7)	10.2	(12.6)
Other current assets and liabilities	(0.8)	2.9	(1.0)
Other non-current assets and liabilities	—	—	(0.2)
Net cash provided by operating activities	97.4	36.6	50.8
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(31.6)	(24.5)	(12.8)
Proceeds from sales of assets	—	—	0.1
Net cash used in investing activities	(31.6)	(24.5)	(12.7)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net change in parent advances	—	(17.1)	(38.1)
Distributions	(86.2)	(44.5)	—
Contributions	29.5	54.3	—
Net cash used in financing activities	(56.7)	(7.3)	(38.1)
Net change in cash and cash equivalents	9.1	4.8	—
Cash and cash equivalents, beginning of period	4.8	—	—
Cash and cash equivalents, end of period	$ 13.9	$ 4.8	$ —

See 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 formed in July 2007 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 and a natural gas liquids fractionator. The facility is connected to our about 900 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, 2008, Midstream owns an approximate 30% interest in Partners, which includes 100% of the general partner interest. Midstream is currently appointed as our operator and is responsible for day-to-day operation, maintenance and repair of our assets and the related managerial and administrative duties. 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 prior to July 1, 2007 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. Intercompany balances and transactions have been eliminated. 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 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 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 original cost. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

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. 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, internally developed discounted cash flow analysis and analyses from outside advisors. 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 natural gas gathering, processing, compression, transportation, and fractionation 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 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 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 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 arrangements* — Under percent-of-proceeds 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 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, sell 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 natural gas gathered. This arrangement keeps the producer whole to the thermal value of the 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.
- *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, credit metrics, liquidity 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 recognized until the cash 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 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, 2008 and 2007 were imbalances totaling $1.1 million and $0.8 million, respectively. Included in the consolidated balance sheets as accounts payable — other as of December 31, 2008 and 2007 were imbalances totaling $0.9 million and $2.9 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. There were no environmental liabilities included in the consolidated balance as of December 31, 2008 and 2007.

Income Taxes — We are structured as a joint venture which is a pass-through entity for federal income tax purposes. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the joint venture and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this 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. East Texas is a member of a consolidated group. We have calculated current and deferred income taxes as if we were a separate taxpayer.

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 2008 and 2007, related to the temporary differences that are expected to reverse in periods when the tax will apply.

3. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles," or SFAS 162 — In May 2008, the FASB issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC's, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133" or SFAS 161 — In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our December 31, 2009 consolidated financial statements.

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 became 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;

- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and
- significantly expands the disclosure requirements around instruments measured at fair value.

Upon adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were 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. There has been no impact to our earnings as a result of adopting SFAS 157. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, 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 are in the process of assessing the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial positions upon adoption.

FASB FSP No. 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active," or FSP 157-3 — In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

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 was $8.3 million as adjusted for changes in the Consumer Price Index. After 2008, the fee shall be mutually agreed upon.

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, 2008, 2007, and 2006.

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,		
	2008	2007 (Millions)	2006
DCP Midstream, LLC:			
Sales of natural gas, NGLs and condensate	$ 284.4	$ 263.2	$ 276.3
Losses from non-trading derivative activity	$ 0.6	$ 0.1	$ 1.1
General and administrative expense	$ 8.5	$ 10.3	$ 11.3
Duke Energy Corporation:			
Sales of natural gas, NGLs and condensate	$ —	$ —	$ 6.6
Purchases of natural gas and NGLs	$ —	$ —	$ 0.1
ConocoPhillips:			
Sales of natural gas, NGLs and condensate	$ 29.3	$ 7.7	$ 3.7
Transportation and processing services	$ 0.2	$ 0.1	$ 0.3
Purchases of natural gas and NGLs	$ 0.1	$ 1.1	$ 9.2

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

	December 31,	
	2008 (Millions)	2007
DCP Midstream LLC:		
Accounts receivable	$ 20.6	$ 64.5
Accounts payable	$ 2.4	$ 1.5
ConocoPhillips:		
Accounts receivable	$ 0.1	$ —

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 $2.3 million and $3.4 million of capital reimbursements during the years ended December 31, 2008 and 2007, respectively. These reimbursements are treated as contributions 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 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 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, 2008	December 31, 2007
		(Millions)	
Gathering systems	15 – 30 Years	$ 92.8	$ 78.9
Processing plants	25 – 30 Years	219.8	218.5
Transportation	25 – 30 Years	42.6	40.0
Underground storage	20 – 50 Years	0.1	—
General plant	3 – 5 Years	7.9	7.8
Construction work in progress		30.3	14.7
		393.5	359.9
Accumulated depreciation		(140.1)	(123.4)
Property, plant and equipment, net		$ 253.4	$ 236.5

Depreciation expense for the years ended December 31, 2008, 2007 and 2006, was $16.7 million, $15.8 million and $14.6 million respectively. At December 31, 2008, we had non-cancelable purchase obligations of approximately $0.8 million for capital projects anticipated to be completed in 2009.

6. 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 $0.6 million, $0.1 million and $1.1 million for the years ended December 31, 2008, 2007 and 2006, 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.

7. 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, 2008, 2007 and 2006 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, 2008 and 2007 included in the consolidated balance sheets as other long-term liabilities was $0.6 million and $0.5 million, respectively.

8. 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 became effective for franchise tax reports due on or after January 1, 2008. The 2008 tax was based on revenues earned during the 2007 fiscal year. Accordingly, we recorded current tax expense for the Texas margin tax for 2008 and 2007 of $0.6 million and $0.8 million, respectively, and a reduction in deferred taxes of $0.1 million for both 2008 and 2007.

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.

9. 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.

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.

10. Supplemental Cash Flow Information

	Year Ended December 31,		
	2008	2007 (Millions)	2006
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 2.0	$ 0.9	$ 3.1
Accrued contributions related to reimbursements	$ —	$ 0.2	$ —

11. Subsequent Events

In February 2009, we announced that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

In February 2009, Midstream entered into an agreement to contribute an additional 25.1% interest in East Texas to Partners in exchange for 3.5 million Class D units. This transaction is expected to close in April 2009. Subsequent to this transaction, Partners will consolidate East Texas in their consolidated financial statements.

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, 2008				
Allowance for doubtful accounts	$ 0.5	$ (0.1)	$ —	$ 0.4
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

(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
3.1	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated as of January 20, 2009 and Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005.
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).
10.7*	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP 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).
10.8*	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).

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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).
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).
10.16	Contribution Agreement dated February 24, 2009, among DCP Midstream Partners, LP, DCP LP Holdings, LLC, DCP Midstream GP, LP and DCP Midstream, LLC.
12.1	Ratio of Earnings to Fixed Charges.
21.1	List of Subsidiaries of DCP Midstream Partners, LP.
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 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, 2008.
99.2	Consolidated Balance Sheet of DCP Midstream, LLC as of December 31, 2008.

* 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 5, 2009.

DCP Midstream Partners, LP

By: /s/ DCP Midstream GP, LP
its General Partner

By: /s/ DCP Midstream GP, LLC
its General Partner

By: /s/ Mark A. Borer
Name: Mark A. Borer
Title: President and Chief Executive Officer

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 Angela A. Minas as his/her 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 5, 2009
/s/ Angela A. Minas Angela A. Minas	Vice President and Chief Financial Officer (Principal Financial Officer)	March 5, 2009
/s/ Scott R. Delmoro Scott R. Delmoro	Chief Accounting Officer (Principal Accounting Officer)	March 5, 2009
/s/ Thomas C. O'Connor Thomas C. O'Connor	Chairman of the Board and Director	March 5, 2009
/s/ Paul F. Ferguson, Jr. Paul F. Ferguson, Jr.	Director	March 5, 2009
/s/ Gregory J. Goff Gregory J. Goff	Director	March 5, 2009
/s/ Alan N. Harris Alan N. Harris	Director	March 5, 2009
/s/ John E. Lowe John E. Lowe	Director	March 5, 2009
/s/ Frank A. McPherson Frank A. McPherson	Director	March 5, 2009
/s/ Thomas C. Morris Thomas C. Morris	Director	March 5, 2009
/s/ Stephen R. Springer Stephen R. Springer	Director	March 5, 2009

EXHIBIT INDEX

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* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

AMENDMENT NO. 1 TO

AMENDED AND RESTATED LIMITED LIABILITY COMPANY AGREEMENT

OF

DCP MIDSTREAM GP, LLC

This Amendment No. 1 to the Amended and Restated Limited Liability Company Agreement (the "***LLC Agreement***") of DCP Midstream GP, LLC (the "***Company***") is hereby adopted, executed and agreed to by DCP Midstream, LLC as Sole Member (***"Sole Member***") of the Company.

WHEREAS, the Sole Member desires to amend the LLC Agreement by revising Section 6.02(e)(ii) of the LLC Agreement.

NOW, THEREFORE BE IT RESOLVED, that the Sole Member does hereby amend the LLC Agreement as follows:

Section 6.02(e)(ii) is hereby amended by deleting the last four words thereof and replacing it with the following:

"In addition to any other committees established by the Board of Directors pursuant to Section 6.02(e)(i), the Board of Directors shall maintain a "***Conflicts Committee***," which shall be composed of at least one Independent Director. The Conflicts Committee shall be responsible for (A) approving or disapproving, as the case may be, any matters regarding the business and affairs of the Company, DCP GP or the MLP considered by, or submitted to, such Conflicts Committee at the request of the Board of Directors pursuant to the terms of the DCP GP Agreement or the MLP Partnership Agreement, (B) approving any material amendments to the Omnibus Agreement, (C) approving or disapproving, as the case may be, the entering into of any material transaction with a Member or any Affiliate of a Member, other than transactions in the ordinary course of business to the extent that the Board of Directors requests the Conflicts Committee to make such determination, (D) amending (1) Section 2.07, (2) the definitions of "Independent Director" in Section 6.02(a) or (3) this Section 6.02(e)(ii), and (E) performing such other functions as the Board may assign from time to time or as may be specified in a written charter of the Conflicts Committee. In acting or otherwise voting on the matters referred to in this Section 6.02(e)(ii), to the fullest extent permitted by law, including Section 18-1101(c) of the Delaware Act and Section 17-1101(c) of the Delaware Revised Uniform Limited Partnership Act, as amended from time to time, the Directors constituting the Conflicts Committee shall consider only the interest of the MLP."

IN WITNESS WHEREOF, the Sole Member has executed this Amendment No. 1 as of January 20, 2009.

DCP Midstream, LLC

By: /s/ Brent L. Backes
Name: Brent L. Backes
Title: Group Vice President, General Counsel and Corporate Secretary

EXECUTION COPY

AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT

OF

DCP MIDSTREAM GP, LLC
A Delaware Limited Liability Company

AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT
OF
DCP MIDSTREAM GP, LLC
A Delaware Limited Liability Company

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AMENDED AND RESTATED
LIMITED LIABILITY COMPANY AGREEMENT
OF
DCP Midstream GP, LLC
A Delaware Limited Liability Company

THIS AMENDED AND RESTATED LIMITED LIABILITY COMPANY AGREEMENT (this "***Agreement***") of DCP Midstream GP, LLC, a Delaware limited liability company (the "***Company***"), executed on December 7, 2005 (the "***Effective Date***"), is adopted, executed and agreed to, by Duke Energy Field Services, LLC, a Delaware limited liability company ("***DEFS***"), as the sole Member of the Company.

RECITALS

A. DEFS formed the Company on August 5, 2005 as the sole member.

B. The Limited Liability Company Agreement of DCP Midstream GP, LLC was executed effective August 5, 2005 (the "***Existing Agreement***").

C. DEFS, the sole Member of the Company, deems it advisable to amend and restate the limited liability company agreement of the Company in its entirety as set forth herein.

AGREEMENTS

For and in consideration of the premises, the covenants and agreements set forth herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, DEFS, as the sole Member of the Company, hereby amends and restates the Existing Agreement in its entirety as follows:

ARTICLE 1
DEFINITIONS

1.01 Definitions. Each capitalized term used herein shall have the meaning given such term in Attachment I.

1.02 Construction. Unless the context requires otherwise: (a) the gender (or lack of gender) of all words used in this Agreement includes the masculine, feminine and neuter; (b) references to Articles and Sections refer to Articles and Sections of this Agreement; (c) references to Laws refer to such Laws as they may be amended from time to time, and references to particular provisions of a Law include any corresponding provisions of any succeeding Law; (d) references to money refer to legal currency of the United States of America; (e) "including" means "including without limitation" and is a term of illustration and not of limitation; (f) all definitions set forth herein shall be deemed applicable whether the words defined are used herein in the singular or the plural; and (g) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsperson hereof or thereof.

ARTICLE 2
ORGANIZATION

2.01 Formation. The Company was organized as a Delaware limited liability company by the filing of a Certificate of Formation ("***Organizational Certificate***") on August 5, 2005 with the Secretary of State of the State of Delaware under and pursuant to the Delaware Act.

2.02 Name. The name of the Company is "DCP Midstream GP, LLC" and all Company business must be conducted in that name or such other names that comply with Law as the Board of Directors may select.

2.03 Registered Office; Registered Agent; Principal Office; Other Offices. The registered office of the Company required by the Delaware Act to be maintained in the State of Delaware shall be the office of the initial registered agent for service of process named in the Organizational Certificate or such other office (which need not be a place of business of the Company) as the Board of Directors may designate in the manner provided by Law. The registered agent for service of process of the Company in the State of Delaware shall be the initial registered agent for service of process named in the Organizational Certificate or such other Person or Persons as the Board of Directors may designate in the manner provided by Law. The principal office of the Company in the United States shall be at such a place as the Board of Directors may from time to time designate, which need not be in the State of Delaware, and the Company shall maintain records there and shall keep the street address of such principal office at the registered office of the Company in the State of Delaware. The Company may have such other offices as the Board of Directors may designate.

2.04 Purpose. The purposes of the Company are the transaction of any or all lawful business for which limited liability companies may be organized under the Delaware Act.

2.05 Term. The period of existence of the Company commenced on August 5, 2005 and shall end at such time as a certificate of cancellation is filed in accordance with Section 9.02(c).

2.06 No State-Law Partnership; Withdrawal. It is the intent that the Company shall be a limited liability company formed under the Laws of the State of Delaware and shall not be a partnership (including a limited partnership) or joint venture, and that the Members not be a partner or joint venturer of any other party for any purposes other than federal and state tax purposes, and this Agreement may not be construed to suggest otherwise. A Member does not have the right to Withdraw from the Company; *provided*, *however*, that a Member shall have the power to Withdraw at any time in violation of this Agreement. If a Member exercises such power in violation of this Agreement, (a) such Member shall be liable to the Company and its Affiliates for all monetary damages suffered by them as a result of such Withdrawal; and (b) such Member shall not have any rights under Section 18.604 of the Delaware Act. In no event shall the Company have the right, through specific performance or otherwise, to prevent a Member from Withdrawing in violation of this Agreement.

2.07 Certain Undertakings Relating to Separateness.

(a) Separateness Generally. The Company shall, and shall cause DCP GP to, conduct their respective businesses and operations in accordance with this Section 2.07.

(b) Separate Records. The Company shall, and shall cause DCP GP to, (i) maintain their respective books and records and their respective accounts separate from those of any other Person, (ii) maintain their respective financial records, which will be used by them in their ordinary course of business, showing their respective assets and liabilities separate and apart from those of any other Person, except their consolidated Subsidiaries, (iii) not have their respective assets and/or liabilities included in a consolidated financial statement of any Affiliate of the Company unless appropriate notation shall be made on such Affiliate's consolidated financial statements to indicate the separateness of the Company and DCP GP and their assets and liabilities from such Affiliate and the assets and liabilities of such Affiliate, and to indicate that the assets and liabilities of the Company and DCP GP are not available to satisfy the debts and other obligations of such Affiliate, and (iv) file their respective own tax returns separate from those of any other Person, except (A) to the extent that the Company or DCP GP (x) is treated as a "disregarded entity" for tax purposes or (y) is not otherwise required to file tax returns under applicable law or (B) as may otherwise be required by applicable law.

(c) Separate Assets. The Company shall not commingle or pool, and shall cause DCP GP not to commingle or pool, their respective funds or other assets with those of any other Person, and shall maintain their respective assets in a manner that is not costly or difficult to segregate, ascertain or otherwise identify as separate from those of any other Person.

(d) Separate Name. The Company shall, and shall cause DCP GP to, (i) conduct their respective businesses in their respective own names, (ii) use separate stationery, invoices, and checks, (iii) correct any known misunderstanding regarding their respective separate identities from that of any other Person (including DEFS and its Subsidiaries other than the Company and DCP GP), and (iv) generally hold itself out as an entity separate from any other Person (including DEFS and its Subsidiaries other than the Company and DCP GP).

(e) Separate Credit. The Company shall, and shall cause DCP GP to, (i) pay their respective obligations and liabilities from their respective own funds (whether on hand or borrowed), (ii) maintain adequate capital in light of their respective business operations, (iii) not guarantee or become obligated for the debts of any other Person, other than the Company and DCP GP and except to the extent specified in the Contribution Agreement or the Omnibus Agreement, (iv) not hold out their respective credit as being available to satisfy the obligations or liabilities of any other Person except to the extent specified in the Contribution Agreement or the Omnibus Agreement, (v) not acquire debt obligations or debt securities of DEFS or its Affiliates (other than the Company and DCP GP), (vi) not pledge their assets for the benefit of any Person or make loans, advances or capital contributions to DEFS or any of its Affiliates (other than the MLP and its Subsidiaries and, with respect to the Company, other than DCP GP), or (vii) use its commercially reasonable efforts to cause the operative documents under which DCP GP borrows money, is an issuer of debt securities, or guarantees any such borrowing or issuance after the Effective Date, to contain provisions to the effect that (A) the lenders or purchasers of debt securities, respectively, acknowledge that they have advanced funds or purchased debt securities, respectively, in reliance upon the separateness of the Company and DCP GP from each other and from any other Persons (including DEFS and its Affiliates, other than the Company and DCP GP) and (B) the Company and DCP GP have assets and liabilities that are separate from those of other persons (including DEFS and its Affiliates, other than the Company and DCP GP); provided that the Company and DCP GP may engage in any transaction described in clauses (v)-(vi) of this Section 2.07(e) if prior Special Approval has been obtained for such transaction and either (A) the Conflicts Committee has determined that the borrower or recipient of the credit support is not then insolvent and will not be rendered insolvent as a result of such transaction or (B) in the case of transactions described in clause (v), such transaction is completed through a public sale or a National Securities Exchange.

(f) Separate Formalities. The Company shall, and shall cause DCP GP to, (i) observe all limited liability company or partnership formalities and other formalities required by their respective organizational documents, the laws of the jurisdiction of their respective formation, or other laws, rules, regulations and orders of governmental authorities exercising jurisdiction over it, (ii) engage in transactions with DEFS and its Affiliates (other than the Company or DCP GP) in conformity with the requirements of Section 7.9 of the DCP GP Agreement, and (iii) subject to the terms of the Omnibus Agreement, promptly pay, from their respective own funds and on a timely basis, their respective allocable shares of general and administrative expenses, capital expenditures, and costs for services performed by DEFS or Affiliates of DEFS (other than the Company or DCP GP). Each material contract between the Company or DCP GP, on the one hand, and DEFS or Affiliates of DEFS (other than the Company or DCP GP), on the other hand, shall be subject to the requirements of Section 7.9 of the DCP GP Agreement, and must be (x) approved by Special Approval or (y) on terms objectively demonstrable to be no less favorable to DCP GP than those generally being provided to or available from unrelated third parties, and in any event must be in writing.

(g) No Effect. Failure by the Company to comply with any of the obligations set forth above shall not affect the status of the Company as a separate legal entity, with its separate assets and separate liabilities or restrict or limit the Company from engaging or contracting with DEFS and its Affiliates for the provision of services or the purchase or sale of products, whether under the Omnibus Agreement or otherwise.

ARTICLE 3
MATTERS RELATING TO MEMBERS

3.01 Members. DEFS has previously been admitted as a Member of the Company.

3.02 Creation of Additional Membership Interest. The Company may issue additional Membership Interests in the Company pursuant to this Section 3.02. The terms of admission or issuance may provide for the creation of different classes or groups of Members having different rights, powers, and duties. The creation of any new class or group of Members approved as required herein may be reflected in an amendment to this Agreement executed in accordance with Section 11.04 indicating the different rights, powers, and duties thereof. Any such admission is effective only after the new Member has executed and delivered to the Members an instrument containing the notice address of the new Member and the new Member's ratification of this Agreement and agreement to be bound by it.

3.03 Liability to Third Parties. No Member or beneficial owner of any Membership Interest shall be liable for the Liabilities of the Company.

ARTICLE 4
CAPITAL CONTRIBUTIONS

4.01 Capital Contributions.

(a) In exchange for its Membership Interest, DEFS has made certain Capital Contributions.

(b) The amount of money and the fair market value (as of the date of contribution) of any property (other than money) contributed to the Company by a Member in respect of the issuance of a Membership Interest to such Member shall constitute a "***Capital Contribution***." Any reference in this Agreement to the Capital Contribution of a Member shall include a Capital Contribution of its predecessors in interest.

4.02 Loans. If the Company does not have sufficient cash to pay its obligations, any Member that may agree to do so may, upon Special Approval, advance all or part of the needed funds for such obligation to or on behalf of the Company. An advance described in this Section 4.02 constitutes a loan from the Member to the Company, may bear interest at a rate comparable to the rate the Company could obtain from third parties, and is not a Capital Contribution.

4.03 Return of Contributions. A Member is not entitled to the return of any part of its Capital Contributions or to be paid interest in respect of its Capital Contributions. An unrepaid Capital Contribution is not a liability of the Company or of any Member. No Member will be required to contribute or to lend any cash or property to the Company to enable the Company to return any Member's Capital Contributions.

ARTICLE 5
DISTRIBUTIONS

5.01 Distributions. Subject to Section 9.02, within 45 days following each Quarter other than any Quarter in which the dissolution of the Company has commenced (the "***Distribution Date***"), the Company shall distribute to the Members the Company's Available Cash on such Distribution Date.

ARTICLE 6
MANAGEMENT

6.01 Management.

(a) All management powers over the business and affairs of the Company shall be exclusively vested in a Board of Directors ("***Board of Directors***" or "***Board***") and, subject to the direction of the Board of Directors, the Officers. The Officers and Directors shall each constitute a "manager" of the Company within the meaning of the Delaware Act. Except as otherwise specifically provided in this Agreement, no Member, by virtue of having the status of a Member, shall have or attempt to exercise or assert any management power over the business and affairs of the Company or shall have or attempt to exercise or assert actual or apparent authority to enter into contracts on behalf of, or to otherwise bind, the Company. Except as otherwise specifically provided in this Agreement, the authority and functions of the Board of Directors on the one hand and of the Officers on the other shall be identical to the authority and functions of the board of directors and officers, respectively, of a corporation organized under the Delaware General Corporation Law. Except as otherwise specifically provided in this Agreement, the business and affairs of the Company shall be managed under the direction of the Board of Directors, and the day-to-day activities of the Company shall be conducted on the Company's behalf by the Officers, who shall be agents of the Company.

(b) In addition to the powers that now or hereafter can be granted to managers under the Delaware Act and to all other powers granted under any other provision of this Agreement, except as otherwise provided in this Agreement, the Board of Directors and the Officers shall have full power and authority to do all things as are not restricted by this Agreement, the DCP GP Agreement, the Delaware Act or applicable Law, on such terms as they may deem necessary or appropriate to conduct, or cause to be conducted, the business and affairs of the Company.

(c) Notwithstanding anything herein to the contrary, without obtaining Extraordinary Approval, the Company shall not, and shall not take any action to cause either DCP GP or the MLP to, (i) make or consent to a general assignment for the benefit of its respective creditors; (ii) file or consent to the filing of any bankruptcy, insolvency or reorganization petition for relief under the United States Bankruptcy Code naming the Company, DCP GP or the MLP, as applicable, or otherwise seek, with respect to the Company, DCP GP or the MLP, relief from debts or protection from creditors generally; (iii) file or consent to the filing of a petition or answer seeking for the Company, DCP GP or the MLP, as applicable, a liquidation, dissolution, arrangement, or similar relief under any law; (iv) file an answer or other pleading admitting or failing to contest the material allegations of a petition filed against the Company, DCP GP or the MLP, as applicable, in a proceeding of the type described in any of clauses (i) — (iii) of this Section 6.01(c); (v) seek, consent to or acquiesce in the appointment of a receiver, liquidator, conservator, assignee, trustee, sequestrator, custodian or any similar official for the Company, DCP GP or the MLP, as applicable, or for all or any substantial portion of either entity's properties; (vi) sell all or substantially all of the assets of the Company, DCP GP or the MLP; (vii) dissolve or liquidate, except in the case of DCP GP, in accordance with Article XII of the DCP GP Agreement; (viii) merge or consolidate; (ix) amend the MLP Partnership Agreement; or (x) make a material change in the amount of the quarterly distributions made on the MLP Interests or the payment of any material extraordinary distribution on the MLP Interests.

(d) Notwithstanding anything herein to the contrary, DEFS, as the sole Member of the Company, shall have exclusive authority over the business and affairs of the Company that do not relate to management and control of the MLP. The type of matter referred to in the prior sentence where DEFS, as the sole Member of the Company, shall have exclusive authority shall include, but not be limited to, (i) the amount and timing of distributions paid by the Company or DCP GP, (ii) the issuance or repurchase of any equity interests in the Company or DCP GP, (iii) the prosecution, settlement or management of any claim made directly against the Company or DCP GP, (iv) whether to sell, convey, transfer or pledge any asset of the Company or DCP GP, (v) whether to amend, modify or waive any rights relating to the assets of the Company or DCP GP (including the decision to amend or forego distributions in respect of the Incentive Distribution Rights), and (vi) whether to enter into any agreement to incur an obligation of the Company or DCP GP other than an agreement entered into for and on behalf of the MLP for which the Company or DCP GP are liable exclusively by virtue of DCP GP's capacity as general partner of the MLP or of any of its affiliates. Further, DEFS, as the sole Member of the Company, shall have exclusive authority to cause the Company to exercise the rights of the Company and those of DCP GP, as general partner of the MLP (or those exercisable after DCP GP ceases to be the general partner of the MLP), pursuant to the following provisions of the MLP Partnership Agreement:

(i) Section 2.4 ("*Purpose and Business*"), with respect to decisions to propose or approve the conduct by the MLP of any business;

(ii) Sections 4.6(a) and (b) ("*Transfer of the General Partner's General Partner Interest*") and Section 4.7 ("*Transfer of Incentive Distribution Rights*"), solely with respect to the decision by DCP GP to transfer its general partner interest in the MLP or its Incentive Distribution Rights;

(iii) Section 5.2(b) ("*Contributions by the General Partner and its Affiliates*"), solely with respect to the decision to make additional Capital Contributions to the MLP;

(iv) Section 5.8 ("*Limited Preemptive Right*");

(v) Section 5.11 ("*Issuance of Class B Units in Connection with Reset of Incentive Distribution Rights*"), with respect to any decision by the Company or DCP GP thereunder as a holder of Incentive Distribution Rights or Class B Units;

(vi) Section 7.5(d) (relating to the right of DCP GP and its Affiliates to purchase Units or other Partnership Securities and exercise rights related thereto) and Section 7.11 ("*Purchase and Sale of Partnership Securities*"), solely with respect to decisions by the Company or DCP GP to purchase or otherwise acquire and sell Partnership Securities for their own account;

(vii) Section 7.6(a) ("*Loans from the General Partner; Loans or Contributions from the Partnership or Group Members*"), solely with respect to the decision by the Company or DCP GP to lend funds to a Group Member, subject to the provisions of Section 7.9 of the MLP Partnership Agreement;

(viii) Section 7.7 ("*Indemnification*"), solely with respect to any decision by the Company or DCP GP to exercise their respective rights as "Indemnitees";

(ix) Section 7.12 ("*Registration Rights of the General Partner and its Affiliates*"), solely with respect to any decision to exercise registration rights and to take actions in connection therewith;

(x) Section 11.1 (“*Withdrawal of the General Partner*”), solely with respect to the decision by DCP GP to withdraw as general partner of the MLP and to giving notices required thereunder;

(xi) Section 11.3(a) and (b) (“*Interest of Departing General Partner and Successor General Partner*”); and

(xii) Section 15.1 (“*Right to Acquire Limited Partner Interests*”).

(e) Without the approval of the Conflicts Committee of the Board of Directors of the Company, the Company shall not take any action that would result in either the Company or DCP GP engaging in any business or activity or incurring any debts or liabilities except in connection with or incidental to (i) its performance as general partner of DCP GP or (ii) the acquiring, owning or disposing of debt or equity securities of DCP GP.

6.02 Board of Directors.

(a) *Generally.* The Board of Directors shall initially consist of five natural persons and, in the discretion of DEFS, may be increased to consist of up to 10 natural persons. The members of the Board of Directors shall be appointed by DEFS, *provided* that (i) at least one member of the Board of Directors at the time of the closing of the initial public offering of common units representing limited partner interest of the MLP (the “IPO”) shall be a natural person who meets the independence, qualification and experience requirements of the New York Stock Exchange, the independence, qualification and experience requirements of Section 10A(m)(3) of the Securities Exchange Act of 1934 (or any successor Law), the rules and regulations of the SEC and other applicable Law (an “***Independent Director***”), (ii) at least two members of the Board of Directors shall be natural persons who are Independent Directors at all times from and after the 90th day following the effective date of the registration statement related to the IPO and (iii) at least three members of the Board of Directors shall be natural persons who are Independent Directors at all times from and after the first anniversary of the effective date of the registration statement relating to the IPO; *provided*, *however*, that if at any time the Board of Directors does not include the requisite number of Independent Directors as specified above, the Board of Directors shall still have all powers and authority granted to it hereunder, but DEFS shall endeavor to appoint one or more additional Independent Directors as necessary to come into compliance with this Section 6.02(a).

(b) *Term; Resignation; Vacancies; Removal.* Each Director, other than any Independent Director, shall hold office until December 31 of the year in which such Director is appointed, provided however, that in the event a Director, other than an Independent Director, is appointed during the month of December in any particular year, such Director shall hold office until December 31 of the year following the year in which such Director is appointed. Each Independent Director shall hold office until his successor is appointed and qualified or until his earlier resignation or removal. Any Director may resign at any time upon written notice to the Board, the Chairman of the Board, to the Chief Executive Officer or to any other Officer. Such resignation shall take effect at the time specified therein, and unless otherwise specified therein no acceptance of such resignation shall be necessary to make it effective. Vacancies and newly created directorships resulting from any increase in the authorized number of Directors or from any other cause shall be filled by DEFS. Any Director may be removed, with or without cause, by DEFS at any time, and the vacancy in the Board caused by any such removal shall be filled by DEFS in accordance with the provisions of the DEFS LLC Agreement.

(c) *Voting; Quorum*. Unless otherwise required by the Delaware Act, other Law or the provisions hereof,

(i) each member of the Board of Directors shall have one vote;

(ii) except for matters requiring Special Approval, the presence at a meeting of a majority of the members of the Board of Directors shall constitute a quorum at any such meeting for the transaction of business; and

(iii) except for matters requiring Special Approval, the act of a majority of the members of the Board of Directors present at a meeting duly called in accordance with Section 6.02(d) at which a quorum is present shall be deemed to constitute the act of the Board of Directors.

(d) *Meetings*. Regular meetings of the Board of Directors shall be held at such times and places as shall be designated from time to time by resolution of the Board of Directors. Special meetings of the Board of Directors or meetings of any committee thereof may be called by written request authorized by any member of the Board of Directors or a committee thereof on at least 48 hours prior written notice to the other members of such Board or committee. Any such notice, or waiver thereof, need not state the purpose of such meeting, except as may otherwise be required by law. Attendance of a Director at a meeting (including pursuant to the last sentence of this Section 6.02(d)) shall constitute a waiver of notice of such meeting, except where such Director attends the meeting for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called or convened. Any action required or permitted to be taken at a meeting of the Board of Directors or any committee thereof may be taken without a meeting, without prior notice and without a vote if a consent or consents in writing, setting forth the action so taken, are signed by at least as many members of the Board of Directors or committee thereof as would have been required to take such action at a meeting of the Board of Directors or such committee. Members of the Board of Directors or any committee thereof may participate in and hold a meeting by means of conference telephone, video conference or similar communications equipment by means of which all Persons participating in the meeting can hear each other, and participation in such meetings shall constitute presence in person at the meeting.

(e) *Committees*.

(i) Subject to compliance with this Article 6, committees of the Board of Directors shall have and may exercise such of the powers and authority of the Board of Directors with respect to the management of the business and affairs of the Company as may be provided in a resolution of the Board of Directors. Any committee designated pursuant to this Section 6.02(e) shall choose its own chairman, shall keep regular minutes of its proceedings and report the same to the Board of Directors when requested, and, subject to Section 6.02(d), shall fix its own rules or procedures and shall meet at such times and at such place or places as may be provided by such rules or by resolution of such committee or resolution of the Board of Directors. At every meeting of any such committee, the presence of a majority of all the members thereof shall constitute a quorum and the affirmative vote of a majority of the members present shall be necessary for the adoption by it of any resolution (except for obtaining Special Approval at meetings of the Conflicts Committee, which requires the affirmative vote of a majority of the members of such committee). The Board of Directors may designate one or more Directors as alternate members of any committee who may replace any absent or disqualified member at any meeting of such committee; *provided*, *however*, that any such designated alternate of the Audit Committee or the Conflicts Committee must meet the standards for an Independent Director. In the absence or disqualification of a member of a committee, the member or members present at any meeting and not disqualified from voting, whether or not constituting a quorum, may unanimously appoint another member of the Board of Directors to act at the meeting in the place of the absent or disqualified member; *provided*, *however*, that any such replacement member of the Audit Committee or the Conflicts Committee must meet the standards for an Independent Director.

(ii) In addition to any other committees established by the Board of Directors pursuant to Section 6.02(e)(i), the Board of Directors shall maintain a "***Conflicts Committee***," which shall be composed of at least one Independent Director. The Conflicts Committee shall be responsible for (A) approving or disapproving, as the case may be, any matters regarding the business and affairs of the Company, DCP GP or the MLP considered by, or submitted to, such Conflicts Committee at the request of the Board of Directors pursuant to the terms of the DCP GP Agreement or the MLP Partnership Agreement, (B) approving any material amendments to the Omnibus Agreement, (C) approving or disapproving, as the case may be, the entering into of any material transaction with a Member or any Affiliate of a Member, other than transactions in the ordinary course of business to the extent that the Board of Directors requests the Conflicts Committee to make such determination, (D) amending (1) Section 2.07, (2) the definitions of "Independent Director" in Section 6.02(a) or (3) this Section 6.02(e)(ii), and (E) performing such other functions as the Board may assign from time to time or as may be specified in a written charter of the Conflicts Committee. In acting or otherwise voting on the matters referred to in this Section 6.02(e)(ii), to the fullest extent permitted by law, including Section 18-1101(c) of the Delaware Act and Section 17-1101(c) of the Delaware Revised Uniform Limited Partnership Act, as amended from time to time, the Directors constituting the Conflicts Committee shall consider only the interest of the MLP, including its respective creditors.

(iii) In addition to any other committees established by the Board of Directors pursuant to Section 6.02(e)(i), the Board of Directors shall maintain an "***Audit Committee***," which shall be composed of (A) at least one Independent Director at the time of the closing of the IPO, (B) at least two Independent Directors at all times from and after the 90th day following the effective date of the registration statement related to the IPO and (C) at least three Independent Directors at all times from and after the first anniversary of the effective date of the registration statement related to the IPO. The Audit Committee shall be responsible for (A) assisting the Board in monitoring (1) the integrity of the MLP's financial statements, (2) the qualifications and independence of the MLP's independent accountants, (3) the performance the internal audit function and independent accountants of the Company, DCP GP and the MLP, and (4) the MLP's compliance with legal and regulatory requirements and (B) preparing the report required by the rules of the SEC to be included in the MLP's annual report on Form 10-K. The Audit Committee shall perform such other functions as the Board may assign from time to time or as may be specified in a written charter for the Audit Committee adopted by the Board.

(iv) In addition to any other committees established by the Board of Directors pursuant to Section 6.02(e)(i), the Board of Directors shall maintain an "***Compensation Committee***," which shall be composed of at least one Independent Director. The Compensation Committee shall be responsible for setting the compensation for officers of the Company as well as administering any incentive plans adopted by the Company. The Compensation Committee shall perform such other functions as the Board may assign from time to time or as may be specified in a written charter for the Compensation Committee adopted by the Board.

6.03 Officers.

(a) *Generally*. The Board of Directors, as set forth below, shall appoint officers of the Company ("***Officers***"), who shall (together with the Directors) constitute "managers" of the Company for the purposes of the Delaware Act. Unless provided otherwise by resolution of the Board of Directors, the Officers shall have the titles, power, authority and duties described below in this Section 6.03.

(b) *Titles and Number*. The Company may appoint one or more officers including a Chairman of the Board (unless the Board of Directors provides otherwise), a Chief Executive Officer, a President, one or more Vice Presidents, a Secretary, the Chief Financial Officer, any Treasurer and one or more Assistant Secretaries and Assistant Treasurers and a General Counsel. Any person may hold more then one office.

(c) *Appointment and Term of Office*. The Officers shall be appointed by the Board of Directors at such time and for such term as the Board of Directors shall determine. Any Officer may be removed, with or without cause, only by the Board of Directors. Vacancies in any office may be filled only by the Board of Directors.

(d) *Chairman of the Board*. The Chairman of the Board shall preside at all meetings of the Board of Directors and of the unitholders of the MLP; and he shall have such other powers and duties as from time to time may be assigned to him by the Board of Directors.

(e) *Chief Executive Officer*. Subject to the limitations imposed by this Agreement, any employment agreement, any employee plan or any determination of the Board of Directors, the Chief Executive Officer, subject to the direction of the Board of Directors, shall be the chief executive officer of the Company and shall be responsible for the management and direction of the day-to-day business and affairs of the Company, its other Officers, employees and agents, shall supervise generally the affairs of the Company and shall have full authority to execute all documents and take all actions that the Company may legally take. In the absence of the Chairman of the Board, the Chief Executive Officer shall preside at all meetings of the unitholders of the MLP and at all meetings of the Board of Directors provided that he is a director of the Company. The Chief Executive Officer shall exercise such other powers and perform such other duties as may be assigned to him by this Agreement or the Board of

Directors, including any duties and powers provided for in any employment agreement approved by the Board of Directors.

(f) *President*. Subject to the limitations imposed by this Agreement, any employment agreement, any employee plan or any determination of the Board of Directors, the President, subject to the direction of the Board of Directors, shall be the chief executive officer of the Company in the absence of a Chief Executive Officer and shall be responsible for the management and direction of the day-to-day business and affairs of the Company, its other Officers, employees and agents, shall supervise generally the affairs of the Company and shall have full authority to execute all documents and take all actions that the Company may legally take. In the absence of the Chairman of the Board and Chief Executive Officer, the President shall preside at all meetings of the unitholders of the MLP and at all meetings of the Board of Directors provided that he is a director of the Company. The President shall exercise such other powers and perform such other duties as may be assigned to him by this Agreement or the Board of Directors, including any duties and powers provided for in any employment agreement approved by the Board of Directors.

(g) *Vice Presidents*. In the absence of a Chief Executive Officer and the President, each Vice President appointed by the Board of Directors shall have all of the powers and duties conferred upon the President, including the same power as the President to execute documents on behalf of the Company. Each such Vice President shall perform such other duties and may exercise such other powers as may from time to time be assigned to him by the Board of Directors or the President.

(h) *Secretary and Assistant Secretaries*. The Secretary shall record or cause to be recorded in books provided for that purpose the minutes of the meetings or actions of the Board of Directors, shall see that all notices are duly given in accordance with the provisions of this Agreement and as required by law, shall be custodian of all records (other than financial), shall see that the books, reports, statements, certificates and all other documents and records required by law are properly kept and filed, and, in general, shall perform all duties incident to the office of Secretary and such other duties as may, from time to time, be assigned to him by this Agreement, the Board of Directors or the President. The Assistant Secretaries shall exercise the powers of the Secretary during that Officer's absence or inability or refusal to act.

(i) *Chief Financial Officer*. The Chief Financial Officer shall keep and maintain, or cause to be kept and maintained, adequate and correct books and records of account of the Company and DCP GP. He shall receive and deposit all moneys and other valuables belonging to the Company in the name and to the credit of the Company and shall disburse the same and only in such manner as the Board of Directors or the appropriate Officer of the Company may from time to time determine. He shall receive and deposit all moneys and other valuables belonging to DCP GP in the name and to the credit of DCP GP and shall disburse the same and only in such manner as the Board of Directors or the Chief Executive Officer may require. He shall render to the Board of Directors and the Chief Executive Officer, whenever any of them request it, an account of all his transactions as Chief Financial Officer and of the financial condition of the Company, and shall perform such further duties as the Board of Directors or the Chief Executive Officer may require. The Chief Financial Officer shall have the same power as the Chief Executive Officer to execute documents on behalf of the Company.

(j) *Treasurer and Assistant Treasurers*. The Treasurer shall have such duties as may be specified by the Chief Financial Officer in the performance of his duties. The Assistant Treasurers shall exercise the power of the Treasurer during that Officer's absence or inability or refusal to act. Each of the Assistant Treasurers shall possess the same power as the Treasurer to sign all certificates, contracts, obligations and other instruments of the Company. If no Treasurer or Assistant Treasurer is appointed and serving or in the absence of the appointed Treasurer and Assistant Treasurer, any Vice President, or such other Officer as the Board of Directors shall select, shall have the powers and duties conferred upon the Treasurer.

(k) *General Counsel*. The General Counsel, subject to the discretion of the Board of Directors, shall be responsible for the management and direction of the day-to-day legal affairs of the Company. The General Counsel shall perform such other duties and may exercise such other powers as may from time to time be assigned to him by the Board of Directors or the President.

(l) *Powers of Attorney*. The Company may grant powers of attorney or other authority as appropriate to establish and evidence the authority of the Officers and other persons.

(m) *Delegation of Authority*. Unless otherwise provided by resolution of the Board of Directors, no Officer shall have the power or authority to delegate to any person such Officer's rights and powers as an Officer to manage the business and affairs of the Company.

(n) *Tenure*. The Board of Directors shall appoint Officers of the Company to serve from the date hereof until the death, resignation or removal by the Board of Directors with or without cause of such Officer.

6.04 Duties of Officers and Directors. Except as otherwise specifically provided in this Agreement or in the MLP Partnership Agreement, the duties and obligations owed to the Company and to the Board of Directors by the Officers of the Company and by members of the Board of Directors of the Company shall be the same as the respective duties and obligations owed to a corporation organized under the Delaware General Corporation Law by its officers and directors, respectively.

6.05 Compensation. The members of the Board of Directors who are neither Officers nor employees of the Company shall be entitled to compensation as directors and committee members as approved by the Board and shall be reimbursed for out-of-pocket expenses incurred in connection with attending meetings of the Board of Directors or committees thereof.

6.06 Indemnification.

(a) To the fullest extent permitted by Law but subject to the limitations expressly provided in this Agreement, each Indemnitee shall be indemnified and held harmless by the Company from and against any and all losses, claims, damages, liabilities, joint or several, expenses (including reasonable legal fees and expenses), judgments, fines, penalties, interest, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any such Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of such person's status as an Indemnitee; *provided*, *however* that the Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Indemnitee is seeking indemnification pursuant to this Section 6.06, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct, or in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was unlawful; *provided*, *further*, no indemnification pursuant to this Section 6.06 shall be available to the Members or their Affiliates (other than the MLP and any Group Member) with respect to its or their obligations incurred pursuant to the Underwriting Agreement, the Omnibus Agreement or the Contribution Agreement. The termination of any action, suit or proceeding by judgment, order, settlement, conviction or upon a plea of *nolo contendere*, or its equivalent, shall not create a presumption that the Indemnitee acted in a manner contrary to that specified above. Any indemnification pursuant to this Section 6.06 shall be made only out of the assets of the Company, it being agreed that the Members shall not be personally liable for such indemnification and shall have no obligation to contribute or loan any monies or property to the Company to enable it to effectuate such indemnification.

(b) To the fullest extent permitted by law, expenses (including reasonable legal fees and expenses) incurred by an Indemnitee who is indemnified pursuant to Section 6.06(a) in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the Company prior to the final disposition of such claim, demand, action, suit or proceeding upon receipt by the Company of an undertaking by or on behalf of the Indemnitee to repay such amount if it shall be determined that the Indemnitee is not entitled to be indemnified as authorized in this Section 6.06.

(c) The indemnification provided by this Section 6.06 shall be in addition to any other rights to which an Indemnitee may be entitled under any agreement, as a matter of law or otherwise, both as to actions in the Indemnitee's capacity as an Indemnitee and as to actions in any other capacity, and shall continue as to an Indemnitee who has ceased to serve in such capacity and shall inure to the benefit of the heirs, successors, assigns and administrators of the Indemnitee.

(d) The Company may purchase and maintain insurance, on behalf of the members of the Board of Directors, the Officers and such other persons as the Board of Directors shall determine, against any liability that may be asserted against or expense that may be incurred by such person in connection with the Company's activities, regardless of whether the Company would have the power to indemnify such person against such liability under the provisions of this Agreement.

(e) For purposes of this Section 6.06, the Company shall be deemed to have requested an Indemnitee to serve as fiduciary of an employee benefit plan whenever the performance by the Indemnitee of such Indemnitee's duties to the Company also imposes duties on, or otherwise involves services by, the Indemnitee to the plan or participants or beneficiaries of the plan; excise taxes assessed on an Indemnitee with respect to an employee benefit plan pursuant to applicable law shall constitute "fines" within the meaning of Section 6.06(a); and action taken or omitted by the Indemnitee with respect to an employee benefit plan in the performance of such Indemnitee's duties for a purpose reasonably believed by such Indemnitee to be in the interest of the participants and beneficiaries of the plan shall be deemed to be for a purpose which is in, or not opposed to, the best interests of the Company.

(f) An Indemnitee shall not be denied indemnification in whole or in part under this Section 6.06 because the Indemnitee had an interest in the transaction with respect to which the indemnification applies if the transaction was otherwise permitted by the terms of this Agreement.

(g) The provisions of this Section 6.06 are for the benefit of the Indemnitees, their heirs, successors, assigns and administrators and shall not be deemed to create any rights for the benefit of any other Persons.

(h) No amendment, modification or repeal of this Section 6.06 or any provision hereof shall in any manner terminate, reduce or impair either the right of any past, present or future Indemnitee to be indemnified by the Company or the obligation of the Company to indemnify any such Indemnitee under and in accordance with the provisions of this Section 6.06 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted, provided such Person became an Indemnitee hereunder prior to such amendment, modification or repeal.

(i) THE PROVISIONS OF THE INDEMNIFICATION PROVIDED IN THIS SECTION 6.06 ARE INTENDED BY THE PARTIES TO APPLY EVEN IF SUCH PROVISIONS HAVE THE EFFECT OF EXCULPATING THE INDEMNITEE FROM LEGAL RESPONSIBILITY FOR THE CONSEQUENCES OF SUCH PERSON'S NEGLIGENCE, FAULT OR OTHER CONDUCT.

6.07 Liability of Indemnitees.

(a) Notwithstanding anything to the contrary set forth in this Agreement, no Indemnitee shall be liable for monetary damages to the Company, the Members or any other Person for losses sustained or liabilities incurred as a result of any act or omission of an Indemnitee unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter in question, the Indemnitee acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that the Indemnitee's conduct was criminal.

(b) Subject to its obligations and duties as set forth in this Article 6, the Board of Directors and any committee thereof may exercise any of the powers granted to it by this Agreement and perform any of the duties imposed upon it hereunder either directly or by or through the Company's Officers or agents, and neither the Board of Directors nor any committee thereof shall be responsible for any misconduct or negligence on the part of any such Officer or agent appointed by the Board of Directors or any committee thereof in good faith.

(c) To the extent that, at law or in equity, an Indemnitee has duties (including fiduciary duties) and liabilities relating thereto to the Partnership or to the Partners, the General Partner and any other Indemnitee acting in connection with the Partnership's business or affairs shall not be liable to the Partnership or to any Partner for any acts or omissions taken in good faith reliance on the provisions of this Agreement.

(d) Any amendment, modification or repeal of this Section 6.07 or any provision hereof shall be prospective only and shall not in any way affect the limitations on liability under this Section 6.07 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may be asserted.

6.08 Outside Activities.

(a) Except as specifically restricted by the provisions of the DCP GP Agreement or the MLP Partnership Agreement, each Indemnitee, other than officers or employees of the Company, shall have the right to engage in businesses of every type and description and other activities for profit and to engage in and possess an interest in other business ventures of any and every type or description, whether in businesses engaged in or anticipated to be engaged in by the Company or its Subsidiaries, independently or with others, including business interests and activities in direct competition with the business and activities of the Company or its Subsidiaries, and none of the same shall constitute a breach of this Agreement or any duty expressed or implied by Law to the Company or its Subsidiaries or any Member. Neither the Company or its Subsidiaries, any Member nor any other Person shall have any rights by virtue of this Agreement, the DCP GP Agreement or the MLP Partnership Agreement or the partnership relationship established hereby or thereby in any business ventures of any Indemnitee.

(b) Notwithstanding anything to the contrary in this Agreement, (i) the engaging in competitive activities by any Indemnitees, other than officers or employees of the Company, in accordance with the provisions of this Section 6.08 is hereby approved by the Company and all Members, (ii) it shall be deemed not to be a breach of any fiduciary duty or any other obligation of any type whatsoever of any Indemnitee, other than officers or employees of the Company, for such Indemnitees to engage in such business interests and activities in preference to or to the exclusion of the Company and (iii) the Indemnitees, other than Officers or employees of the Company, shall have no obligation hereunder or as a result of any duty expressed or implied by Law to present business opportunities to the Company, DCP GP or the MLP.

(c) Each Member and each of its Affiliates may acquire additional Membership Interests and, except as otherwise provided in this Agreement, shall be entitled to exercise, at their option, all rights relating to such Membership Interests.

6.09 Resolution of Conflicts of Interest; Standard of Conduct and Modification of Duties.

(a) Unless otherwise expressly provided in this Agreement, whenever a potential conflict of interest exists or arises between the Members or any of their Affiliates (other than the MLP or any Group Member), on the one hand, and the MLP or any Group Member, on the other hand, any resolution or course of action by the Board of Directors in respect of such conflict of interest shall be permitted and deemed approved by all Members, and shall not constitute a breach of this Agreement or of any agreement contemplated herein or therein, or of any duty stated or implied by law or equity, if the resolution or course of action in respect of such conflict of interest is (i) approved by Special Approval, (ii) approved by the vote of a majority of the Units excluding Units owned by the Members and their Affiliates, (iii) on terms no less favorable to the MLP or Group Member, as the case may be, than those generally being provided to or available from unrelated third parties or (iv) fair and reasonable to the MLP or Group Member, as the case may be, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the MLP or Group Member, as the case may be). The Board of Directors shall be authorized but not required in connection with its resolution of such conflict of interest to seek Special Approval of such resolution, and the Board of Directors may also adopt a resolution or course of action that has not received Special Approval. If Special Approval is not sought and the Board of Directors determines that the resolution or course of action taken with respect to a conflict of interest satisfies either of the standards set forth in clauses (iii) or (iv) above, then it shall be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by any Member or by or on behalf of such Member or the MLP or Group Member, as the case may be, challenging such approval, the Person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption.

(b) Whenever the Company makes a determination or takes or declines to take any other action, or any of its Affiliates causes it to do so, in its capacity as the general partner of the General Partner of the MLP as opposed to in its individual capacity, whether under this Agreement, or any other agreement contemplated hereby or otherwise, then unless another express standard is provided for in this Agreement, the Company, or such Affiliates causing it to do so, shall make such determination or take or decline to take such other action in good faith and shall not be subject to any other or different standards imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation or at equity. In order for a determination or other action to be in “good faith” for purposes of any action taken or delivered to be taken by the Company in its capacity as the general partner of the General Partner of the MLP, the Person or Persons making such determination or taking or declining to take such other action must believe that the determination or other action is in the best interests of the MLP.

(c) Whenever the Company makes a determination or takes or declines to take any other action, or any of its Affiliates causes it to do so, in its individual capacity as opposed to in its capacity as a general partner of the General Partner of the MLP, whether under this Agreement or any other agreement contemplated hereby or otherwise, then the Company, or such Affiliates causing it to do so, are entitled to make such determination or to take or decline to take such other action free of any fiduciary duty or obligation whatsoever to the MLP or any partner thereof, and the Company, or such Affiliates causing it to do so, shall not be required to act in good faith or pursuant to any other standard imposed by this Agreement, any other agreement contemplated hereby or under the Delaware Act or any other law, rule or regulation. By way of illustration and not of limitation, whenever the phrase, “at the option of the Company,” or some variation of that phrase, is used in this Agreement, it indicates that the Company is acting in its individual capacity. For the avoidance of doubt, whenever the Company votes or transfers its MLP Interests, or refrains from voting or transferring its MLP Interests, it shall be acting in its individual capacity.

(d) Notwithstanding anything to the contrary in this Agreement, the Company and its Affiliates shall have no duty or obligation, express or implied, to (i) sell or otherwise dispose of any asset of the MLP or any Group Member or (ii) permit the MLP or any Group Member to use any facilities or assets of the Company and its Affiliates, except as may be provided in contracts entered into from time to time specifically dealing with such use. Any determination by the Company or any of its Affiliates to enter into such contracts shall be at its option.

(e) Whenever a particular transaction, arrangement or resolution of a conflict of interest is required under this Agreement to be "fair and reasonable" to any Person, the fair and reasonable nature of such transaction, arrangement or resolution shall be considered in the context of all similar or related transactions.

ARTICLE 7
TAX MATTERS

7.01 Tax Returns and Tax Characterization.

(a) The Board of Directors shall cause to be prepared and timely filed (on behalf of the Company) all federal, state and local tax returns required to be filed by the Company, including making all elections on such tax returns. The Company shall bear the costs of the preparation and filing of its returns.

(b) The Company and the Member acknowledge that for federal income tax purposes, the Company will be disregarded as an entity separate from the Member pursuant to Treasury Regulation §301.7701-3 as long as all of the Membership Interests in the Company are owned by DEFS.

ARTICLE 8
BOOKS, RECORDS, REPORTS, AND BANK ACCOUNTS

8.01 Maintenance of Books.

(a) The Board of Directors shall keep or cause to be kept at the principal office of the Company or at such other location approved by the Board of Directors complete and accurate books and records of the Company, supporting documentation of the transactions with respect to the conduct of the Company's business and minutes of the proceedings of the Board of Directors and any other books and records that are required to be maintained by applicable Law.

(b) The books of account of the Company shall be maintained on the basis of a fiscal year that is the calendar year and on an accrual basis in accordance with United States generally accepted accounting principles, consistently applied.

8.02 Reports. The Board of Directors shall cause to be prepared and delivered to each Member such reports, forecasts, studies, budgets and other information as the Members may reasonably request from time to time.

8.03 Bank Accounts. Funds of the Company shall be deposited in such banks or other depositories as shall be designated from time to time by the Board of Directors. All withdrawals from any such depository shall be made only as authorized by the Board of Directors and shall be made only by check, wire transfer, debit memorandum or other written instruction.

ARTICLE 9
DISSOLUTION, WINDING-UP AND TERMINATION

9.01 Dissolution.

(a) Subject to compliance with Section 6.01(c), the Company shall dissolve and its affairs shall be wound up on the first to occur of the following events (each a "***Dissolution Event***"):

(i) the unanimous consent of the Board of Directors;

(ii) the entry of a decree of judicial dissolution of the Company under Section 18-802 of the Delaware Act; and

(iii) at any time there are no Members of the Company, unless the Company is continued in accordance with the Delaware Act or this Agreement.

(b) No other event shall cause a dissolution of the Company.

(c) Upon the occurrence of any event that causes there to be no Members of the Company, to the fullest extent permitted by law, the personal representative of the last remaining Member is hereby authorized to, and shall, within 90 days after the occurrence of the event that terminated the continued membership of such Member in the Company, agree in writing (i) to continue the Company and (ii) to the admission of the personal representative or its nominee or designee, as the case may be, as a substitute Member of the Company, effective as of the occurrence of the event that terminated the continued membership of such Member in the Company.

(d) Notwithstanding any other provision of this Agreement, the Bankruptcy of a Member shall not cause such Member to cease to be a member of the Company, and, upon the occurrence of such an event, the Company shall continue without dissolution.

9.02 Winding-Up and Termination.

(a) On the occurrence of a Dissolution Event, the Board of Directors shall select one or more Persons to act as liquidator. The liquidator shall proceed diligently to wind up the affairs of the Company and make final distributions as provided herein and in the Delaware Act. The costs of winding up shall be borne as a Company expense. Until final distribution, the liquidator shall continue to operate the Company properties with all of the power and authority of the Board of Directors. The steps to be accomplished by the liquidator are as follows:

(i) as promptly as possible after dissolution and again after final winding up, the liquidator shall cause a proper accounting to be made by a recognized firm of certified public accountants of the Company's assets, liabilities, and operations through the last calendar day of the month in which the dissolution occurs or the final winding up is completed, as applicable;

(ii) the liquidator shall discharge from Company funds all of the debts, liabilities and obligations of the Company or otherwise make adequate provision for payment and discharge thereof (including the establishment of a cash escrow fund for contingent liabilities in such amount and for such term as the liquidator may reasonably determine); and

(iii) all remaining assets of the Company shall be distributed to the Members as follows:

(A) the liquidator may sell any or all Company property, including to Members; and

(B) Company property (including cash) shall be distributed to the Members.

(b) The distribution of cash or property to a Member in accordance with the provisions of this Section 9.02 constitutes a complete return to the Member of its Capital Contributions and a complete distribution to the Member of its share of all the Company's property and constitutes a compromise to which all Members have consented within the meaning of Section 18-502(b) of the Delaware Act. No Member shall be required to make any Capital Contribution to the Company to enable the Company to make the distributions described in this Section 9.02.

(c) On completion of such final distribution, the liquidator shall file a certificate of cancellation with the Secretary of State of the State of Delaware and take such other actions as may be necessary to terminate the existence of the Company.

ARTICLE 10
MERGER, CONSOLIDATION OR CONVERSION

10.01 Authority. Subject to compliance with Section 6.01(c), the Company may merge or consolidate with one or more corporations, limited liability companies, statutory trusts or associations, real estate investment trusts, common law trusts or unincorporated businesses, including a partnership (whether general or limited (including a limited liability partnership)) or convert into any such entity, whether such entity is formed under the laws of the State of Delaware or any other state of the United States of America, pursuant to a written agreement of merger or consolidation ("***Merger Agreement***") or a written plan of conversion ("***Plan of Conversion***"), as the case may be, in accordance with this Article 10. The surviving entity to any such merger, consolidation or conversion is referred to herein as the "***Surviving Business Entity***."

10.02 Procedure for Merger, Consolidation or Conversion.

(a) The merger, consolidation or conversion of the Company pursuant to this Article 10 requires the prior approval of a majority of the Board of Directors and compliance with Section 10.03.

(b) If the Board of Directors shall determine to consent to a merger or consolidation, the Board of Directors shall approve the Merger Agreement, which shall set forth:

(i) the names and jurisdictions of formation or organization of each of the business entities proposing to merge or consolidate;

(ii) the name and jurisdiction of formation or organization of the Surviving Business Entity that is to survive the proposed merger or consolidation;

(iii) the terms and conditions of the proposed merger or consolidation;

(iv) the manner and basis of exchanging or converting the equity securities of each constituent business entity for, or into, cash, property or interests, rights, securities or obligations of the Surviving Business Entity; and (A) if any general or limited partner interests, securities or rights of any constituent business entity are not to be exchanged or converted solely for, or into, cash, property or general or limited partner interests, rights, securities or obligations of the Surviving Business Entity, the cash, property or interests, rights, securities or obligations of any general or limited partnership, corporation, trust, limited liability company, unincorporated business or other entity (other than the Surviving Business Entity) which the holders of such general or limited partner interests, securities or rights are to receive in exchange for, or upon conversion of their interests, securities or rights, and (B) in the case of securities represented by certificates, upon the surrender of such certificates, which cash, property or general or limited partner interests, rights, securities or obligations of the Surviving Business Entity or any general or limited partnership, corporation, trust, limited liability company, unincorporated business or other entity (other than the Surviving Business Entity), or evidences thereof, are to be delivered;

(v) a statement of any changes in the constituent documents or the adoption of new constituent documents (the articles or certificate of incorporation, articles of trust, declaration of trust, certificate or agreement of limited partnership, operating agreement or other similar charter or governing document) of the Surviving Business Entity to be effected by such merger or consolidation;

(vi) the effective time of the merger, which may be the date of the filing of the certificate of merger pursuant to Section 10.04 or a later date specified in or determinable in accordance with the Merger Agreement (provided, that if the effective time of the merger is to be later than the date of the filing of such certificate of merger, the effective time shall be fixed at a date or time certain at or prior to the time of the filing of such certificate of merger and stated therein); and

(vii) such other provisions with respect to the proposed merger or consolidation as are deemed necessary or appropriate by the Board of Directors.

(c) If the Board of Directors shall determine to consent to the conversion, the Board of Directors shall approve and adopt a Plan of Conversion containing such terms and conditions that the Board of Directors determines to be necessary or appropriate.

10.03 Approval by Members of Merger or Consolidation.

(a) The Board of Directors, upon its approval of the Merger Agreement or Plan of Conversion, as the case may be, shall direct that the Merger Agreement or the Plan of Conversion, as applicable, be submitted to a vote of the Members, whether at a meeting or by written consent. A copy or a summary of the Merger Agreement or the Plan of Conversion, as applicable, shall be included in or enclosed with the notice of a special meeting or the written consent.

(b) The Merger Agreement or the Plan of Conversion, as applicable, shall be approved upon receiving the affirmative vote or consent of the holders of a majority of the Members.

(c) After such approval by vote or consent of the Limited Partners, and at any time prior to the filing of the certificate of merger, consolidation or conversion pursuant to Section 10.04, the merger, consolidation or conversion may be abandoned pursuant to provisions therefor, if any, set forth in the Merger Agreement or the Plan of Conversion, as the case may be.

10.04 Certificate of Merger, Consolidation or Conversion.

(a) Upon the required approval, if any, by the Board of Directors and the Members of a Merger Agreement or a Plan of Conversion, as the case may be, a certificate of merger, consolidation or conversion, as applicable, shall be executed and filed with the Secretary of State of the State of Delaware in conformity with the requirements of the Delaware Act.

(b) At the effective time of the certificate of merger or consolidation:

(i) all of the rights, privileges and powers of each of the business entities that has merged or consolidated, and all property, real, personal and mixed, and all debts due to any of those business entities and all other things and causes of action belonging to each of those business entities shall be vested in the Surviving Business Entity and after the merger or consolidation shall be the property of the Surviving Business Entity to the extent they were property of each constituent business entity;

(ii) the title to any real property vested by deed or otherwise in any of those constituent business entities shall not revert and is not in any way impaired because of the merger or consolidation;

(iii) all rights of creditors and all liens on or security interest in property of any of those constituent business entities shall be preserved unimpaired; and

(iv) all debts, liabilities and duties of those constituent business entities shall attach to the Surviving Business Entity, and may be enforced against it to the same extent as if the debts, liabilities and duties had been incurred or contracted by it.

(c) At the effective time of the certificate of conversion:

(i) the Company shall continue to exist, without interruption, but in the organizational form of the converted entity rather than in its prior organizational form;

(ii) all rights, title, and interests to all real estate and other property owned by the Company shall continue to be owned by the converted entity in its new organizational form without reversion or impairment, without further act or deed, and without any transfer or assignment having occurred, but subject to any existing liens or other encumbrances thereon;

(iii) all liabilities and obligations of the Company shall continue to be liabilities and obligations of the converted entity in its new organizational form without impairment or diminution by reason of the conversion;

(iv) all rights of creditors or other parties with respect to or against the prior interest holders or other owners of the Company in their capacities as such in existence as of the effective time of the conversion will continue in existence as to those liabilities and obligations and may be pursued by such creditors and obligees as if the conversion did not occur;

(v) a proceeding pending by or against the Company or by or against any of the Members in their capacities as such may be continued by or against the converted entity in its new organizational form and by or against the prior members without any need for substitution of parties; and

(vi) the Company securities that are to be converted into partnership interests, shares, evidences of ownership, or other securities in the converted entity as provided in the Plan of Conversion or certificate of conversion shall be so converted, and the Members shall be entitled only to the rights provided in the Plan of Conversion or certificate of conversion.

(d) A merger, consolidation or conversion effected pursuant to this Article 10 shall not (i) be deemed to result in a transfer or assignment of assets or liabilities from one entity to another having occurred or (ii) require the Company (if it is not the Surviving Business Entity) to wind up its affairs, pay its liabilities or distribute its assets as required under Article 9 of this Agreement or under the applicable provisions of the Delaware Act.

ARTICLE 11
GENERAL PROVISIONS

11.01 Notices. Except as expressly set forth to the contrary in this Agreement, all notices, requests or consents provided for or permitted to be given under this Agreement must be in writing and must be delivered to the recipient in person, by courier or mail or by facsimile or other electronic transmission and a notice, request or consent given under this Agreement is effective on receipt by the Person to receive it; *provided*, *however*, that a facsimile or other electronic transmission that is transmitted after the normal business hours of the recipient shall be deemed effective on the next Business Day. All notices, requests and consents to be sent to a Member must be sent to or made at the addresses given for that Member as that Member may specify by notice to the other Members. Any notice, request or consent to the Company must be given to all of the Members. Whenever any notice is required to be given by applicable Law, the Organizational Certificate or this Agreement, a written waiver thereof, signed by the Person entitled to notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice. Whenever any notice is required to be given by Law, the Organizational Certificate or this Agreement, a written waiver thereof, signed by the Person entitled to notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice.

11.02 Entire Agreement; Supersedure. This Agreement constitutes the entire agreement of the Members and their respective Affiliates relating to the subject matter hereof and supersedes all prior contracts or agreements with respect to such subject matter, whether oral or written.

11.03 Effect of Waiver or Consent. Except as provided in this Agreement, a waiver or consent, express or implied, to or of any breach or default by any Person in the performance by that Person of its obligations with respect to the Company is not a consent or waiver to or of any other breach or default in the performance by that Person of the same or any other obligations of that Person with respect to the Company. Except as provided in this Agreement, failure on the part of a Person to complain of any act of any Person or to declare any Person in default with respect to the Company, irrespective of how long that failure continues, does not constitute a waiver by that Person of its rights with respect to that default until the applicable statute-of-limitations period has run.

11.04 Amendment or Restatement. This Agreement may be amended or restated only by a written instrument executed by all Members; *provided*, *however*, that notwithstanding anything to the contrary contained in this Agreement, each Member agrees that the Board of Directors, without the approval of any Member, may amend any provision of the Organizational Certificate and this Agreement, and may authorize any Officer to execute, swear to, acknowledge, deliver, file and record any such amendment and whatever documents may be required in connection therewith, to reflect any change that does not require consent or approval (or for which such consent or approval has been obtained) under this Agreement or does not materially adversely affect the rights of the Members.

11.05 Binding Effect. This Agreement is binding on and shall inure to the benefit of the Members and their respective heirs, legal representatives, successors and assigns.

11.06 Governing Law; Severability. THIS AGREEMENT IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAW OF THE STATE OF DELAWARE, EXCLUDING ANY CONFLICT-OF-LAWS RULE OR PRINCIPLE THAT MIGHT REFER THE GOVERNANCE OR THE CONSTRUCTION OF THIS AGREEMENT TO THE LAW OF ANOTHER JURISDICTION. In the event of a direct conflict between the provisions of this Agreement and (a) any provision of the Organizational Certificate, or (b) any mandatory, non-waivable provision of the Delaware Act, such provision of the Organizational Certificate or the Delaware Act shall control. If any provision of the Delaware Act provides that it may be varied or superseded in the limited liability company agreement (or otherwise by agreement of the members or managers of a limited liability company), such provision shall be deemed superseded and waived in its entirety if this Agreement contains a provision addressing the same issue or subject matter. If any provision of this Agreement or the application thereof to any Person or circumstance is held invalid or unenforceable to any extent, (a) the remainder of this Agreement and the application of that provision to other Persons or circumstances is not affected thereby and that provision shall be enforced to the greatest extent permitted by Law, and (b) the Members or Directors (as the case may be) shall negotiate in good faith to replace that provision with a new provision that is valid and enforceable and that puts the Members in substantially the same economic, business and legal position as they would have been in if the original provision had been valid and enforceable.

11.07 Further Assurances. In connection with this Agreement and the transactions contemplated hereby, each Member shall execute and deliver any additional documents and instruments and perform any additional acts that may be necessary or appropriate to effectuate and perform the provisions of this Agreement and those transactions.

11.08 Offset. Whenever the Company is to pay any sum to any Member, any amounts that a Member owes the Company may be deducted from that sum before payment.

11.09 Counterparts. This Agreement may be executed in any number of counterparts with the same effect as if all signing parties had signed the same document. All counterparts shall be construed together and constitute the same instrument.

IN WITNESS WHEREOF, DEFS has executed this Agreement as the sole member as of the date first set forth above.

MEMBER:

DUKE ENERGY FIELD SERVICES, LLC

By: /s/ Brent L. Backes
Name: Brent L. Backes
Title: Vice President, General Counsel and Secretary

Signature Page — Amended and Restated Limited Liability Agreement of DCP Midstream GP, LLC

Attachment I

Defined Terms

Affiliate — with respect to any Person, each Person Controlling, Controlled by or under common Control with such first Person; provided that, for the evidence of doubt, the term “Affiliate,” includes any Person that, directly or indirectly, is the beneficial owner of at least 25% of the equity interest in DEFS or has the right to appoint at least 25% of the members of the board of directors of DEFS.

Agreement — this Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC, as the same may be amended, modified, supplemented or restated from time to time.

Audit Committee — Section 6.02(e)(iii).

Available Cash — as of any Distribution Date, (a) all cash and cash equivalents of the Company on hand on such date, less (b) the amount of any cash reserves determined to be appropriate by the Board of Directors.

Bankruptcy* or *Bankrupt — with respect to any Person, that (a) such Person (i) makes an assignment for the benefit of creditors; (ii) files a voluntary petition in bankruptcy; (iii) is insolvent, or has entered against such Person an order for relief in any bankruptcy or insolvency proceeding; (iv) files a petition or answer seeking for such Person any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under any Law; (v) files an answer or other pleading admitting or failing to contest the material allegations of a petition filed against such Person in a proceeding of the type described in subclauses (i) through (iv) of this clause (a); or (vi) seeks, consents to or acquiesces in the appointment of a trustee, receiver or liquidator of such Person or of all or any substantial part of such Person’s properties; or (b) 120 Days have passed after the commencement of any proceeding seeking reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under any Law, if the proceeding has not been dismissed, or 90 Days have passed after the appointment without such Person’s consent or acquiescence of a trustee, receiver or liquidator of such Person or of all or any substantial part of such Person’s properties, if the appointment is not vacated or stayed, or 90 Days have passed after the date of expiration of any such stay, if the appointment has not been vacated.

Board of Directors* or *Board — Section 6.01.

Business Day — any Day other than a Saturday, a Sunday or a Day on which national banking associations in the State of Texas are authorized or required by Law to close.

Capital Contribution — Section 4.01(b).

Class B Units has the meaning ascribed to such term in the MLP Partnership Agreement.

Commitment — means (a) options, warrants, convertible securities, exchangeable securities, subscription rights, conversion rights, exchange rights, or other contracts, agreements or commitments that could require a Person to issue any of its Equity Interests or to sell any Equity Interests it owns in another Person; (b) any other securities convertible into, exchangeable or exercisable for, or representing the right to subscribe for any Equity Interest of a Person or owned by a Person; (c) statutory or contractual pre-emptive rights or pre-emptive rights granted under a Person's organizational or constitutive documents; and (d) stock appreciation rights, phantom stock, profit participation, or other similar rights with respect to a Person.

Company — initial paragraph of this Agreement.

Compensation Committee — Section 6.02(e)(iv)

***Conflicts Committee* —** Section 6.02(e)(ii).

Contribution Agreement has the meaning ascribed to such term in the MLP Partnership Agreement.

***Control* —** shall mean the possession, directly or indirectly, of the power and authority to direct or cause the direction of the management and policies of a Person, whether through ownership or control of Voting Stock, by contract or otherwise.

Day — a calendar Day; *provided*, *however*, that, if any period of Days referred to in this Agreement shall end on a Day that is not a Business Day, then the expiration of such period shall be automatically extended until the end of the first succeeding Business Day.

DCP GP — DCP Midstream GP, LP, as the general partner of the MLP.

DCP GP Agreement — the First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP, dated effective as of December 7, 2005, as amended, supplemented, amended and restated, or otherwise modified from time to time.

DEFS — initial paragraph of this Agreement.

DEFS LLC Agreement — means the Second Amended and Restated Limited Liability Company Agreement of DEFS.

Delaware Act — the Delaware Limited Liability Company Act and any successor statute, as amended from time to time.

Delaware General Corporation Law — Title 8 of the Delaware Code, as amended from time to time.

Director — each member of the Board of Directors elected as provided in Section 6.02.

Dissolution Event — Section 9.01(a).

Distribution Date — Section 5.01.

Effective Date — initial paragraph of this Agreement.

Equity Interest — (a) with respect to a corporation, any and all shares of capital stock and any Commitments with respect thereto, (b) with respect to a partnership, limited liability company, trust or similar Person, any and all units, interests or other partnership, limited liability company, trust or similar interests, and any Commitments with respect thereto, and (c) any other direct or indirect equity ownership or participation in a Person (including any incentive distribution rights).

Existing Agreement — Recitals.

Extraordinary Approval — written approval of DEFS.

Group Member — means any of the MLP and its Subsidiaries.

Incentive Distribution Rights — has the meaning ascribed thereto in the MLP Partnership Agreement.

Indemnitee — each of (a) the Company and any Person who is or was an Affiliate of the Company, (b) any Person who is or was a member, director, officer, fiduciary or trustee of the Company, (c) any Person who is or was an officer, member, partner, director, employee, agent or trustee of the General Partner or any Affiliate of the General Partner, or any Affiliate of any such Person, and (d) any Person who is or was serving at the request of the General Partner or any such Affiliate as a director, officer, employee, member, partner, agent, fiduciary or trustee of another Person; provided, that a Person shall not be an Indemnitee by reason of providing, on a fee-for-services basis, trustee, fiduciary or custodial services and (e) any Person the Company designates as an "Indemnitee" for purposes of this Agreement.

Independent Director — Section 6.02(a).

Law — any applicable constitutional provision, statute, act, code, law, regulation, rule, ordinance, order, decree, ruling, proclamation, resolution, judgment, decision, declaration or interpretative or advisory opinion or letter of a governmental authority.

Liability — any liability or obligation, whether known or unknown, asserted or unasserted, absolute or contingent, matured or unmatured, conditional or unconditional, latent or patent, accrued or unaccrued, liquidated or unliquidated, or due or to become due.

Member — any Person executing this Agreement as of the date of this Agreement as a member or hereafter admitted to the Company as a member as provided in this Agreement, but such term does not include any Person who has ceased to be a member in the Company.

Membership Interest — with respect to any Member, (a) that Member's status as a Member; (b) that Member's share of the income, gain, loss, deduction and credits of, and the right to receive distributions from, the Company; (c) all other rights, benefits and privileges enjoyed by that Member (under the Delaware Act, this Agreement or otherwise) in its capacity as a Member; and (d) all obligations, duties and liabilities imposed on that Member (under the Delaware Act, this Agreement or otherwise) in its capacity as a Member, including any obligations to make Capital Contributions.

Merger Agreement — Section 10.01.

MLP — DCP Midstream Partners, LP, a Delaware limited partnership.

MLP Interests — the limited partner interests of the MLP, regardless of class or category of limited partner interests.

MLP Partnership Agreement — means the Amended and Restated Agreement of Limited Partnership of the MLP, dated as of December 7, 2005, as amended or restated from time to time.

National Securities Exchange has the meaning ascribed to such term in the MLP Partnership Agreement.

Officers — any person elected as an officer of the Company as provided in Section 6.03(a), but such term does not include any person who has ceased to be an officer of the Company.

Omnibus Agreement — Omnibus Agreement, dated December 7, 2005, among the Company, DCP GP and DEFS, as amended or restated from time to time.

Organizational Certificate — Section 2.01.

Partnership Securities has the meaning ascribed to such term in the MLP Partnership Agreement.

Person — a natural person, partnership (whether general or limited), limited liability company, governmental entity, trust, estate, association, corporation, venture, custodian, nominee or any other individual or entity in its own or any representative capacity.

Plan of Conversion — Section 10.01.

Quarter — unless the context requires otherwise, a calendar quarter.

SEC — the United States Securities and Exchange Commission.

Special Approval —approval by a majority of the members of the Conflicts Committee.

Subsidiary — with respect to any relevant Person, (a) a corporation of which more than 50% of the Voting Stock is owned, directly or indirectly, at the date of determination, by such relevant Person, by one or more Subsidiaries of such relevant Person or a combination thereof, (b) a partnership (whether general or limited) in which such relevant Person, one or more Subsidiaries of such relevant Person or a combination thereof is, at the date of determination, a general or limited partner of such partnership, but only if more than 50% of the partnership interests of such partnership (considering all of the partnership interests of the partnership as a single class) is owned, directly or indirectly, at the date of determination, by such relevant Person, by one or more Subsidiaries of such relevant Person, or a combination thereof, or (c) any other Person (other than a corporation or a partnership) in which such relevant Person, one or more Subsidiaries of such relevant Person, or a combination thereof, directly or indirectly, at the date of determination, has (i) at least a majority ownership interest or (ii) the power to elect or direct the election of a majority of the directors or other governing body of such other Person.

Surviving Business Entity — Section 10.01.

Underwriting Agreement has the meaning ascribed to such term in the MLP Partnership Agreement.

Units has the meaning ascribed to such term in the MLP Partnership Agreement.

Voting Stock — with respect to any Person, Equity Interests in such Person, the holders of which are ordinarily, in the absence of contingencies, entitled to vote for the election of, or otherwise appoint, directors (or Persons with management authority performing similar functions) of such Person.

Withdraw, Withdrawing and Withdrawal — the withdrawal, resignation or retirement of a Member from the Company as a Member.

Exhibit 10.16

CONTRIBUTION AGREEMENT

among

DCP LP Holdings, LLC,
DCP Midstream GP, LP,
DCP Midstream, LLC

and

DCP Midstream Partners, LP

February 24, 2009

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CONTRIBUTION AGREEMENT

This Contribution Agreement ("Agreement") is dated as of February 24, 2009 (the "Execution Date") and is by and among DCP LP Holdings, LLC, a Delaware limited liability company ("HOLDINGS"), DCP Midstream GP, LP, a Delaware limited partnership ("GP"), DCP Midstream, LLC, a Delaware limited liability company ("MIDSTREAM"), and DCP Midstream Partners, LP, a Delaware limited partnership ("MLP"). HOLDINGS, GP, MIDSTREAM, and MLP are sometimes referred to collectively herein as the "Parties" and individually as a "Party".

R E C I T A L S

A. Pursuant to the Prior Contribution Agreement, MIDSTREAM, through HOLDINGS and GP conveyed 25% of the outstanding membership interests in DCP East Texas Holdings, LLC, a Delaware limited liability company (the "JV") to MLP.

B. Immediately prior to the date hereof, MIDSTREAM owned 75% of the outstanding membership interests in the JV, and MLP owned 25% of the outstanding membership interests in the JV.

C. The JV owns all of the membership interests in FCV, ET and DETG, which collectively own and operate certain midstream gathering, compression, dehydrating, processing and fractionating assets located in Panola, Harrison, Shelby, and Rusk Counties, Texas, and Caddo and DeSoto Parishes, Louisiana including the Former UP Fuels Properties and the Former Gulf South Properties, which are generally depicted on the System Map (the "East Texas System").

D. On the Closing Date, MIDSTREAM shall cause a 25.1% interest in the JV (the "Subject Interests") to be contributed to HOLDINGS and GP as capital contributions.

E. The Parties then desire that HOLDINGS and GP then contribute the Subject Interests to MLP for the consideration and in accordance with the terms of this Agreement.

FOR GOOD AND VALUABLE CONSIDERATION, the receipt and sufficiency of which are hereby acknowledged, MLP, GP, MIDSTREAM, and HOLDINGS agree as follows:

ARTICLE I
CERTAIN DEFINITIONS

1.1 Certain Defined Terms. Capitalized terms used herein and not defined elsewhere in this Agreement shall have the meanings given such terms as is set forth below.

"Affiliate" means, when used with respect to a specified Person, any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with the specified Person as of the time or for the time periods during which such determination is made. For purposes of this definition "control", when used with respect to any specified Person, means the power to direct the management and policies of the Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms “controlling” and “controlled” have the meanings correlative to the foregoing. Notwithstanding the foregoing, except for the JV, the term “Affiliate” when applied to (a) MLP shall not include Spectra Energy Corp, a Delaware corporation, or ConocoPhillips, a Delaware corporation, or any entities owned, directly or indirectly, by Spectra Energy Corp or ConocoPhillips, other than entities owned, directly or indirectly, by MLP and GP and (b) HOLDINGS or GP shall not include MLP or any entities owned, directly or indirectly, by MLP.

“Amendment No. 2” shall mean Amendment No. 2 to that certain Second Amended and Restated Agreement of Limited Partnership of MLP dated as the Effective Time and in the form of Exhibit D hereto.

“Annual Financial Statements” shall have the meaning given such term in Section 4.21(a).

“Arbitral Dispute” means any dispute, claim, counterclaim, demand, cause of action, controversy and other matters in question arising out of or relating to this Agreement or the alleged breach hereof, or in any way relating to the subject matter of this Agreement or the relationship between the Parties created by this Agreement, regardless of whether (a) allegedly extra-contractual in nature, (b) sounding in contract, tort, or otherwise, (c) provided for by applicable Law or otherwise, or (d) seeking damages or any other relief, whether at Law, in equity, or otherwise.

“Arbitration Rules” shall have the meaning given such term in Section 11.8(d).

“Assets” shall mean all of the following assets and properties of the JV (and its respective Subsidiaries), except for the Excluded Assets:

(a) Personal Property. All tangible personal property of every kind and nature that relates to the ownership, operation, use or maintenance of the Facilities, including meters, valves, engines, field equipment, office equipment, fixtures, trailers, tools, instruments, spare parts, machinery, computer equipment, telecommunications equipment, furniture, supplies and materials that are located at the Facilities, and all hydrocarbon inventory at the Facilities, including linefill (collectively the “Personal Property”);

(b) Real Property. All fee property, rights-of-way, easements, surface use agreements, licenses and leases that relate to the ownership, operation, use or maintenance of the Facilities, (collectively, the “Real Property Interests”), and all fixtures, buildings and improvements located on or under such Real Property Interests;

(c) Permits. All assignable permits, licenses, certificates, orders, approvals, authorizations, grants, consents, concessions, warrants, franchises and similar rights and privileges which are necessary for, or are used or held for use primarily for or in connection with, the ownership, use, operation or maintenance of the Assets (collectively, the “Permits”);

(d) Contract Rights. All contracts that relate to the ownership, operation, use or maintenance of the Assets, including all gathering, processing, balancing and other agreements for the handling of natural gas or liquids, purchase and sales agreements, storage agreements, transportation agreements, equipment leases, rental contracts, and service agreements (collectively, the "Contracts");

(e) Intellectual Property. All technical information, shop rights, designs, plans, manuals, specifications and other proprietary and nonproprietary technology and data used in connection with the ownership, operation, use or maintenance of the Assets (collectively, the "Intellectual Property");

(f) Facilities. All meter stations, gas processing plants, treaters, dehydration units, compressor stations, fractionators, liquid handling facilities, platforms, warehouses, field offices, control buildings, pipelines, tanks and other associated facilities that are used or held for use in connection with the ownership, operation or maintenance of the East Texas System (collectively, the "Facilities");

(g) Books and Records. All contract, land, title, engineering, environmental, operating, accounting, business, marketing, and other data, files, documents, instruments, notes, correspondence, papers, ledgers, journals, reports, abstracts, surveys, maps, books, records and studies which relate primarily to the Assets or which are used or held for use primarily in connection with, the ownership, operation, use or maintenance of the Assets; *provided*, *however*, such material shall not include (i) any proprietary data that is not primarily used in connection with the continued ownership, use or operation of the Assets, (ii) any information subject to Third Person confidentiality agreements for which a consent or waiver cannot be secured by HOLDINGS or GP after reasonable efforts, (iii) any information which, if disclosed, would violate an attorney-client privilege or would constitute a waiver of rights as to attorney work product or attorney-client privileged communications, or (iv) any information relating primarily to the Reserved Liabilities or any obligations for which HOLDINGS or GP is required to indemnify the MLP Indemnitees pursuant to Section 10.2 (collectively, the "Records"); provided, however, that MLP shall have the right to copy any of the information specified in clause (iv); and

(h) Incidental Rights. All of the following insofar as the same are attributable or relate primarily to any of the Assets described in clauses (a) through (g): (i) all purchase orders, invoices, storage or warehouse receipts, bills of lading, certificates of title and documents, (ii) all keys, lock combinations, computer access codes and other devices or information necessary to gain entry to and/or take possession of such Assets, (iii) all rights in any confidentiality or nonuse agreements relating to the Assets, and (iv) the benefit of and right to enforce all covenants, warranties, guarantees and suretyship agreements running in favor of the Entities relating primarily to the Assets and all security provided primarily for payment or performance thereof.

"Assumed Obligations" shall mean any and all obligations and liabilities with respect to or arising out of (i) the JV LLC Agreement and attributable to the Subject Interests, (ii) the ownership of the Subject Interests, and (iii) the Hedge.

"Benefit Plan" shall mean any of the following: (a) any employee welfare benefit plan or employee pension benefit plan as defined in sections 3(1) and 3(2) of ERISA, and (b) any other material employee benefit agreement or arrangement, including a deferred compensation plan, incentive plan, bonus plan or arrangement, stock option plan, stock purchase plan, stock award plan, golden parachute agreement, severance plan, dependent care plan, cafeteria plan, employee assistance program, scholarship program, employment contract, retention incentive agreement, non-competition agreement, consulting agreement, vacation policy, and other similar plan, agreement and arrangement.

"Business Day" shall mean any day, other than Saturday and Sunday, on which federally-insured commercial banks in Denver, Colorado are generally open for business and capable of sending and receiving wire transfers.

"Capital Projects" shall have the meaning given such term in Section 6.9.

"Casualty Loss" shall mean, with respect to all or any portion of the Assets, any destruction by fire, storm or other casualty, or any condemnation or taking or threatened condemnation or taking, of all or any portion of the Assets.

"Certificate of Common Units" shall mean a certificate representing Units in the MLP in the form of the attached Exhibit C.

"Claim" shall mean any demand, demand letter, claim or notice by a Third Person of noncompliance or violation or Proceeding.

"Claim Notice" shall have the meaning given such term in Section 10.3(c).

"Closing" shall have the meaning given such term in Section 8.1.

"Closing Date" shall have the meaning given such term in Section 8.1.

"Code" shall mean the U.S. Internal Revenue Code of 1986, as amended.

"Commercially Reasonable Efforts" shall mean efforts which are reasonably within the contemplation of the Parties on the date hereof, which are designed to enable a Party, directly or indirectly, to satisfy a condition to, or otherwise assist in the consummation of, the transactions contemplated by this Agreement and which do not require the performing Party to expend any funds or assume liabilities other than expenditures and liabilities which are reasonable in nature and amount in the context of the transactions contemplated by this Agreement.

"Consideration" has the meaning defined in Section 2.2.

"Contracts" shall have the meaning given such term in the definition of Assets.

"Defensible Title" shall mean, as to the Assets, such title to the Assets that vests the applicable Entity with indefeasible title in and to the Assets free and clear of Liens other than Permitted Encumbrances.

"DETG" shall mean DCP East Texas Gathering, LLC, a Delaware limited liability company.

"East Texas Casualty Incident" shall mean the fire and related property damage to the Facilities that occurred on or about February 11, 2009.

"East Texas System" shall have the meaning given such term in the Recitals.

"Effective Time" shall mean 12:01 A.M. Denver time on April 1, 2009 (or, if the Closing Date occurs later than April 1, 2009, 12:01 A.M. Denver time on the Closing Date).

"Entities" shall mean FCV, ET, DETG and the JV.

"Environmental Law" shall mean any and all Laws, statutes, ordinances, rules, regulations, or orders of any Governmental Authority in existence at the Effective Time pertaining to employee health, public safety, pollution or the protection of the environment or natural resources or to Hazardous Materials in any and all jurisdictions in which the party in question owns property or conducts business or in which the Assets are located, including the Clean Air Act, the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA"), the Federal Water Pollution Control Act, the Occupational Safety and Health Act of 1970 (to the extent relating to environmental matters), the Resource Conservation and Recovery Act of 1976 ("RCRA"), the Safe Drinking Water Act, the Toxic Substances Control Act, the Hazardous & Solid Waste Amendments Act of 1984, the Superfund Amendments and Reauthorization Act of 1986, the Hazardous Materials Transportation Act, the Oil Pollution Act of 1990, any state or local Laws implementing or substantially equivalent to the foregoing federal Laws, and any state or local Laws pertaining to the handling of oil and gas exploration, production, gathering, and processing wastes or the use, maintenance, and closure of pits and impoundments.

"Environmental Matter" shall have the meaning given such term in Section 4.4(b).

"ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended.

"ET" shall mean EasTrans, LLC, a Delaware limited liability company.

"Excluded Assets" shall mean all of the following:

(a) Any deposits or pre-paid items attributable to the operation of the Assets not paid by or on behalf of the JV;

(b) [Reserved];

(c) Claims for refund of or loss carry forwards with respect to (i) Taxes attributable to the business of the Entities for any period prior to the Prior Contribution Agreement Closing Date or (ii) any Taxes attributable to any of the Excluded Assets;

(d) All work product of HOLDINGS' or its Affiliates' attorneys, records relating to the negotiation and consummation of the transactions contemplated hereby and documents that are subject to a valid attorney client privilege;

(e) the real property, personal property, contracts, intellectual property, Permits, office computers or other equipment (or any leases or licenses of the foregoing), if any, that are listed on Schedule 1.1(a);

(f) All vehicles, and all leases for vehicles that relate to the ownership, operation, use or maintenance of the Assets;

(g) All computer software that relates to the ownership, operation, use or maintenance of the Assets that requires a consent to transfer;

(h) All rights and obligations under those certain swaps, futures and similar derivative based transactions listed in Schedule 1.1(b);

(i) All office equipment and accessories (including computers) that relate to the ownership, operation, use or maintenance of the Assets, other than that located at the Facilities; and

(j) Without limiting the obligations under Sections 6.2, all rights to claim coverage or benefits under any insurance policies or coverage applicable to the JV, the Entities or the Assets, including self-insurance and insurance obtained through a captive insurance carrier, but excluding any such rights to recover amounts that are included in the calculation of Net Working Capital.

"Exhibits" shall mean any and/or all of the exhibits attached to and made a part of this Agreement.

"Execution Date" shall have the meaning given such term in the opening paragraph of this Agreement.

"Existing JV Interests" shall mean the Interests in the JV acquired by MLP pursuant to the Prior Contribution Agreement.

"Facilities" shall have the meaning given such term within the definition of Assets.

"FCV" shall mean Fuels Cotton Valley Gathering, LLC, a Delaware limited liability company.

"Final Settlement Statement" shall have the meaning given such term in Section 3.3.

"Former Gulf South Properties" shall mean the former Gulf South gathering facilities located in Shelby, Panola and Harrison Counties, Texas and Caddo Parish, Louisiana, which are generally depicted on the System Map, and which were acquired by DCP Midstream, LP or its Affiliates on March 31, 2005.

"Former UP Fuels Properties" shall mean the former UP Fuels gathering and processing facilities located in Panola, Shelby, Harrison and Rusk Counties, Texas, and Caddo and DeSoto Parishes, Louisiana, which are generally depicted on the System Map, and which were acquired by DCP Midstream, LP or its Affiliates on April 1, 1999.

"GAAP" means generally accepted accounting principles in the United States as of the date hereof, consistently applied.

"GP" shall have the meaning given such term in the introductory paragraph.

"Governmental Authorities" shall mean (a) the United States of America or any state or political subdivision thereof within the United States of America and (b) any court or any governmental or administrative department, commission, board, bureau or agency of the United States of America or of any state or political subdivision thereof within the United States of America.

"HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

"Hazardous Materials" shall mean: (a) any wastes, chemicals, materials or substances defined or included in the definition of "hazardous substances," "hazardous materials," "toxic substances," "solid wastes," "pollutants," "contaminants," or words of similar import, under any Environmental Law; (b) any hydrocarbon or petroleum or component thereof, (including, without limitation, crude oil, natural gas, natural gas liquids, or condensate that is not reasonably and commercially recoverable; (c) oil and gas exploration or production wastes including produced water; (d) radioactive materials (other than naturally occurring radioactive materials), friable asbestos, mercury, lead based paints and polychlorinated biphenyls, (e) any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any Governmental Authority; or (f) any regulated constituents or substances in concentrations or levels that exceed numeric or risk-based standards established pursuant to Environmental Laws.

"Hedge" shall mean that certain financial swap transaction, with MLP as the fixed price payor and HOLDINGS (or its Affiliate that is acceptable to MLP) as the floating price payor for the period of April 1, 2009 through March 31, 2010,.

"Hedge Confirmation" shall mean the document used to evidence the Hedge in the form of Exhibit E.

"HOLDINGS" shall have the meaning given such term in the introductory paragraph.

"HOLDINGS' Indemnitees" shall have the meaning given such term in Section 10.1.

"HOLDINGS' Knowledge" or the "Knowledge of HOLDINGS" or any similar term, shall mean the actual knowledge of (a) any officer of HOLDINGS having a title of Vice President or higher, and (b) the individuals listed on Schedule 1.1(c).

"HOLDINGS' Required Consents" shall have meaning given such term in Section 4.4(a).

"Indemnified Party" or "Indemnitee" shall have the meaning given such term in Section 10.4(a).

"Indemnifying Party" or "Indemnitor" shall have the meaning given such term in Section 10.4(a).

"Independent Accountants" shall mean PricewaterhouseCoopers.

"Inlet AFE" shall have the meaning set forth in Schedule 6.9.

"Intellectual Property" shall have the meaning given such term in the definition of Assets.

"Interest Rate" shall mean three (3) months LIBOR plus one-half of one percent (0.5%).

"JV" shall have the meaning given such term in the Recitals.

"JV LLC Agreement" shall mean the Amended and Restated Limited Liability Company Agreement of DCP East Texas Holdings, LLC dated July 1, 2007, and from and after the Effective Time, as amended and restated by the Second Amended and Restated Limited Liability Company Agreement.

"Laws" shall mean all applicable statutes, laws (including common law), regulations, rules, rulings, ordinances, orders, restrictions, requirements, writs, judgments, injunctions, decrees and other official acts of or by any Governmental Authority.

"Lien" shall mean any lien, mortgage, pledge, claim, charge, security interest or other encumbrance, option or defect on title.

"LIBOR" shall mean the British Bankers' Association interbank offered rates as of 11:00 a.m. London time for deposits in Dollars that appear on the relevant page of the Reuters service (currently page LIBOR01) or, if not available, on the relevant pages of any other service (such as Bloomberg Financial Markets Service) that displays such British Bankers' Association rates.

"Limited Partnership Agreement" shall mean the Second Amended and Restated Agreement of Limited Partnership of MLP dated as of November 1, 2006, as amended by Amendment No. 1 dated April 11, 2008, and from and after the Effective Time, as amended by Amendment No. 2.

"Loss" or "Losses" shall mean any and all damages, demands, payments, obligations, penalties, assessments, disbursements, claims, costs, liabilities, losses, causes of action, and expenses, including interest, awards, judgments, settlements, fines, fees, costs of defense and reasonable attorneys' fees, costs of accountants, expert witnesses and other professional advisors and costs of investigation and preparation of any kind or nature whatsoever.

"Material Adverse Effect" shall mean a single event, occurrence or fact, or series of events, occurrences or facts, that, alone or together with all other events, occurrences or facts (a) would have an adverse change in or effect on the Entities or the Assets (including the cost to remedy, replace or obtain same) taken as a whole, in excess of $2,250,000 or (b) would result in the prohibition or material delay in the consummation of the transactions contemplated by this Agreement, excluding (in each case) matters that are generally industry-wide developments or changes or effects resulting from changes in Law or general economic, regulatory or political conditions.

“Material Casualty Loss” shall have the meaning given such term in Section 6.2.

“Materiality Condition” shall have the meaning given such term in Section 10.5.

“MIDSTREAM” shall have the meaning given such term in the introductory paragraph.

“MLP” shall have the meaning given such term in the introductory paragraph.

“MLP Indemnitees” shall have the meaning given such term in Section 10.2.

“MLP’s Knowledge” or the “Knowledge of MLP” or any similar term, shall mean the actual knowledge of any officer of MLP having a title of vice president or higher.

“MLP Required Consents” shall have the meaning given such term in Section 5.4.

“Net Working Capital” means, as to the JV, and determined as of the Effective Time, an amount (which may be positive or negative) equal to (i) the total current assets of the JV and its Subsidiaries minus (ii) the total current liabilities of the JV and its Subsidiaries, in each case determined in accordance with GAAP.

“New Capital Projects” shall have the meaning given such term in Section 6.9(b).

“Notice Period” shall have the meaning given such term in Section 10.4(c).

“Ordinary Course of Business” shall mean the ordinary course of business consistent with past practices.

“Permits” shall have the meaning given such term in the definition of Assets.

“Permitted Encumbrances” shall mean the following:

(a) the terms, conditions, restrictions, exceptions, reservations, limitations, and other matters contained in any document creating the Real Property Interests, or in any Permit or Contract;

(b) Liens for property Taxes and assessments that are not yet due and payable (or that are being contested in good faith by appropriate Proceedings for which adequate reserves in accordance with GAAP have been established on the books of account of the applicable Entity);

(c) mechanic’s, materialmen’s, repairmen’s and other statutory Liens arising in the Ordinary Course of Business and securing obligations incurred prior to the Effective Time and (i) for which adequate reserves in accordance with GAAP have been established on the books of account of the applicable Entity, or (ii) that are not delinquent and that will be paid and discharged in the Ordinary Course of Business or, if delinquent, that are being contested in good faith with any action to foreclose on or attach any Assets on account thereof properly stayed and for which adequate reserves in accordance with GAAP have been established on the books of account of the applicable Entity;

(d) utility easements, restrictive covenants, defects and irregularities in title, encumbrances, exceptions and other matters that are of record that, singularly or in the aggregate, will not materially interfere with the ownership, use or operation of the Assets to which they pertain;

(e) required Third Person consents to assignment, preferential purchase rights and other similar agreements with respect to which consents or waivers are obtained from the appropriate Person for the transaction contemplated hereby prior to Closing or, as to which the appropriate time for asserting such rights has expired as of the Closing without an exercise of such rights;

(f) any Post-Closing Consent;

(g) Liens created by MLP or its successors or assigns; and

(h) the Liens listed on Schedule 1.1(e).

"Person" shall mean any natural person, corporation, company, partnership (general or limited), limited liability company, trust, joint venture, joint stock company, unincorporated organization, or other entity or association.

"Personal Property" shall have the meaning given such term in the definition of Assets.

"Post-Closing Consents" shall mean consents or approvals from, or filings with Governmental Authorities or consents from railroads customarily obtained following the closing of transactions involving the transfer of assets similar to those owned by the Entities, as listed on Schedule 4.3.

"Pre-Closing Tax Period" shall mean, with respect to the Entities, any taxable period ending on or prior to the Closing Date.

"Preliminary Settlement Statement" shall have the meaning given such term in Section 3.2.

"Prior Contribution Agreement" shall mean that certain Contribution Agreement dated May 23, 2007 among HOLDINGS, MIDSTREAM, GP and MLP.

"Prior Contribution Agreement Closing Date" shall mean July 1, 2007.

"Proceeding" shall mean any action, suit, claim, investigation, review or other judicial or administrative proceeding, at Law or in equity, before or by any Governmental Authority or arbitration or other dispute resolution proceeding.

"Qualified Claims" shall have the meaning given such term in Section 10.3(b)(iii).

"Real Property Interests" shall have the meaning given such term in the definition of Assets.

"Records" shall have the meaning given such term in the definition of Assets.

"Reserved Liabilities" shall mean Losses (but only to the extent not reflected in Net Working Capital) with respect to:

(i) except for sales, transfer, use or similar Taxes that are due or should hereafter become due (including penalty and interest thereon) by reason of creation of the JV and the conveyances and transactions contemplated by this Agreement, 75% of the amount of Taxes with respect to the Entities or the Assets to the extent related to periods prior to and including the Closing Date;

(ii) disposal of Hazardous Materials at offsite locations (a) which were delivered from the East Texas System (excluding the Former Gulf South Properties) between April 1, 1999 and the Closing Date and (b) which were delivered from the Former Gulf South Properties between March 31, 2005 and the Closing Date; provided, however, that the Reserved Liabilities shall only include 75% of this form of Loss to the extent disposal occurred after the Prior Contribution Agreement Closing Date; and

(iii) the Excluded Assets and Taxes related thereto; and

(iv) those matters, if any, described on Schedule 1.1(f).

"Schedules" shall mean any and/or all of the schedules attached to and made a part of this Agreement.

"SEC" shall mean the U.S. Securities and Exchange Commission.

"SEC Financial Statements" shall mean collectively the Annual Financial Statements.

"Securities Act" shall mean the Securities Act of 1933, as amended.

"Settlement Notice" shall have the meaning given such term in Section 3.4.

"Subject Interests" shall have the meaning given such term in the Recitals.

"Subject Interests Assignment Agreement" shall mean the Assignment Agreement in substantially the form of Exhibit B covering the conveyance of the Subject Interests by HOLDINGS and GP to MLP.

"Subsidiary" means, with respect to any Person, (a) any corporation, of which a majority of the total voting power of shares of stock entitled (without regard to the occurrence of any contingency) to vote generally in the election of directors thereof is at the time owned or controlled, directly or indirectly, by that Person or one or more of the other Subsidiaries of that Person or a combination thereof or (b) any limited liability company, partnership, association or other business entity, of which a majority of the partnership or other similar ownership interests thereof is at the time owned or controlled, directly or indirectly, by that Person or one or more Subsidiaries of that Person or a combination thereof.

"System Map" shall collectively mean the maps depicting the East Texas System, which maps are attached as Schedules 1.1(g).

"Tax" or "Taxes" shall mean any federal, state, local or foreign income tax, ad valorem tax, excise tax, sales tax, use tax, franchise tax, real or personal property tax, transfer tax, gross receipts tax or other tax, assessment, duty, fee, levy or other governmental charge, together with and including, any and all interest, fines, penalties, assessments, and additions to Tax resulting from, relating to, or incurred in connection with any of those or any contest or dispute thereof.

"Tax Authority" shall mean any Governmental Authority having jurisdiction over the payment or reporting of any Tax.

"Tax Benefits" means the amount by which the Tax liability of the Indemnified Party or any of its Affiliates for a taxable period is actually reduced (including by deduction, reduction in income upon a sale, disposition or other similar transaction as a result of increased tax basis, receipt of a refund of Taxes or use of a credit of Taxes) plus any related interest (net of Taxes payable thereon) received from the relevant Tax Authority, as a result of the incurrence, accrual or payment of any Loss or Tax with respect to which the indemnification payment is being made.

"Tax Return" shall mean any report, statement, form, return or other document or information required to be supplied to a Tax Authority in connection with Taxes.

"Third Person" shall mean (i) any Person other than a Party or its Affiliates, and (ii) any Governmental Authority.

"Third Person Awards" shall mean any actual recoveries from Third Persons by the Indemnified Party (including from insurance and third-party indemnification) in connection with the claim for which such party is also potentially liable.

"Total Net Working Capital" means the amount (which may be positive or negative) equal to the product of the Net Working Capital multiplied by 25.1%.

"Transaction Documents" shall mean the JV LLC Agreement, Amendment No. 2, the Subject Interests Assignment Agreement, such certificate or other documents as are necessary to transfer the Units to HOLDINGS and GP pursuant to Section 2.2, the Hedge Confirmation, and any other document related to the sale, transfer, assignment or conveyance of the Subject Interests to be delivered at Closing.

"Treasury Regulations" shall mean regulations promulgated under the Code.

"Units" shall mean the Class D limited partnership interests issuable by MLP upon execution of Amendment No. 2.

1.2 Other Definitional Provisions. As used in this Agreement, unless expressly stated otherwise or the context requires otherwise, (a) all references to an "Article," "Section," or "subsection" shall be to an Article, Section, or subsection of this Agreement, (b) the words "this Agreement," "hereof," "hereunder," "herein," "hereby," or words of similar import shall refer to this Agreement as a whole and not to a particular Article, Section, subsection, clause or other subdivision hereof, (c) the words used herein shall include the masculine, feminine and neuter gender, and the singular and the plural, (d) the word "including" means "including, without limitation" and (e) the word "day" or "days" means a calendar day or days, unless otherwise denoted as a Business Day.

1.3 Headings. The headings of the Articles and Sections of this Agreement and of the Schedules and Exhibits are included for convenience only and shall not be deemed to constitute part of this Agreement or to affect the construction or interpretation hereof or thereof.

1.4 Other Terms. Other terms may be defined elsewhere in the text of this Agreement and shall have the meaning indicated throughout this Agreement.

ARTICLE II
CONTRIBUTION OF THE SUBJECT INTERESTS,
ISSUANCE OF THE UNITS AND CONSIDERATION

2.1 The Transaction. Upon the terms and subject to the conditions of this Agreement, at the Closing, but effective for all purposes as of the Effective Time, HOLDINGS and GP shall contribute to MLP the Subject Interests and the Hedge in exchange for the issuance of the Consideration to HOLDINGS and GP pursuant to Section 2.2, and MLP shall assume and thereafter timely perform and discharge in accordance with their respective terms, all Assumed Obligations.

2.2 Consideration. In consideration of HOLDINGS' and GP's contribution of the Subject Interests and the Hedge, MLP shall (i) issue and deliver to HOLDINGS and GP at the Closing one or more certificates duly registered in the names of HOLDINGS and GP and representing in the case of HOLDINGS, three million, two hundred thirty-one thousand, seven hundred fifty (3,231,750) Units and in the case of GP, two hundred sixty-eight thousand, two hundred fifty (268,250) Units (such 3,500,000 Units being referred to herein collectively as, the "Consideration") and (ii) distribute an amount of cash to HOLDINGS and GP, in the aggregate, equal to (A) the Total Net Working Capital and (B) 25.1% of amounts paid or accrued between the Execution Date and the Closing by HOLDINGS or GP for New Capital Projects; *provided*, *however*, if the sum set forth in Section 2.2(ii) is a negative number, such value shall be paid by HOLDINGS and GP to MLP at the Closing, and *provided*, *further*, that to the extent cash is distributed pursuant to Section 2.2(ii), such amounts shall be allocated between and paid to HOLDINGS and GP in proportion to the number of Units issued to each of them.

ARTICLE III
ADJUSTMENTS AND SETTLEMENT

3.1 Adjustments.

(a) The value of the Total Net Working Capital shall be subject to cash adjustments pursuant to this Article III.

(b) The Parties shall use all Commercially Reasonable Efforts to agree upon the adjustments set forth in this Article III, and to resolve any differences with respect thereto. Except as provided herein, no adjustments shall be made after delivery of the Final Settlement Statement.

3.2 Preliminary Settlement Statement. Not later than five (5) business days before the Closing Date, and after consultation with MLP, HOLDINGS shall deliver to MLP a written statement (the "Preliminary Settlement Statement") setting forth the Total Net Working Capital and each component therein, as determined in good faith by HOLDINGS that are described in the definition thereof, with HOLDINGS' calculation of such items in reasonable detail, based on information then available to HOLDINGS. The Preliminary Settlement Statement shall also set forth wire transfer instructions for the Closing payments. Payment of the Total Net Working Capital at the Closing shall be based on the Preliminary Settlement Statement.

3.3 Final Settlement Statement. No later than ninety (90) days after the Closing Date and after consultation with MLP, HOLDINGS shall deliver to MLP a revised settlement statement showing in reasonable detail its calculation of the items described in the definition of Total Net Working Capital along with other adjustments or payments contemplated in this Agreement (said revised statement and the calculation thereof shall be referred to as the "Final Settlement Statement").

3.4 Dispute Procedures. The Final Settlement Statement shall become final and binding on the Parties on the 45th day following the date the Final Settlement Statement is received by MLP, unless prior to such date MLP delivers written notice to HOLDINGS of its disagreement with the Final Settlement Statement (a "Settlement Notice"). Any Settlement Notice shall set forth MLP's proposed changes to the Final Settlement Statement, including an explanation in reasonable detail of the basis on which MLP proposes such changes. If MLP has timely delivered a Settlement Notice, MLP and HOLDINGS shall use good faith efforts to reach written agreement on the disputed items. If the disputed items have not been resolved by MLP and HOLDINGS by the 30th day following HOLDINGS' receipt of a Settlement Notice, any remaining disputed items shall be submitted to the Independent Accountants for resolution within ten (10) Business Days after the end of the foregoing 30-day period. The fees and expenses of the Independent Accountants shall be borne fifty percent (50%) by HOLDINGS and fifty percent (50%) by MLP. The Independent Accountants' determination of the disputed items shall be final and binding upon the Parties, and the Parties hereby waive any and all rights to dispute such resolution in any manner, including in court, before an arbiter or appeal.

3.5 Payments. If the final calculated amount as set forth in the Final Settlement Statement exceeds the estimated calculated amount as set forth in the Preliminary Settlement Statement, then MLP shall pay to HOLDINGS the amount of such excess, with interest at the Interest Rate (calculated from the Closing Date). If the final calculated amount as set forth in the Final Settlement Statement is less than the estimated calculated amount as set forth in the Preliminary Settlement Statement, then HOLDINGS shall pay to MLP the amount of such excess, with interest at the Interest Rate (calculated from the Closing Date). Any payment shall be made within three (3) Business Days of the date the Final Settlement Statement becomes final pursuant to Section 3.4.

3.6 Access to Records. The Parties shall grant to each other full access to the Records and relevant personnel to allow each of them to make evaluations under this Article III.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF HOLDINGS

HOLDINGS represents and warrants to MLP as follows:

4.1 Organization, Good Standing, and Authority.

(a) GP is a limited partnership duly formed, validly existing and in good standing under the Laws of the State of Delaware. The execution and delivery of this Agreement and the other Transaction Documents to which GP is a party and the consummation by GP of the transactions contemplated herein and therein have been duly and validly authorized by all necessary limited partnership action by GP. This Agreement has been duly executed and delivered by GP. GP has all requisite limited partnership power and authority to enter into and perform this Agreement and the other Transaction Documents to which it is a party, to perform its obligations hereunder and thereunder and to carry out the transactions contemplated herein and therein.

(b) Each of HOLDINGS and MIDSTREAM is a limited liability company duly formed, validly existing and in good standing under the Laws of the State of Delaware. The execution and delivery of this Agreement and the other Transaction Documents to which HOLDINGS and MIDSTREAM is a party and the consummation by HOLDINGS and MIDSTREAM of the transactions contemplated herein and therein have been duly and validly authorized by all necessary limited liability company action by HOLDINGS and MIDSTREAM, respectively. This Agreement has been duly executed and delivered by HOLDINGS and MIDSTREAM. Each of HOLDINGS and MIDSTREAM has all requisite limited liability company power and authority to enter into and perform this Agreement and the other Transaction Documents to which it is a party, to perform its obligations hereunder and thereunder and to carry out the transactions contemplated herein and therein.

(c) The JV, ET, FCV and DETG are limited liability companies duly formed, validly existing and in good standing under the Laws of the State of Delaware and have all requisite limited liability company power and authority to own or otherwise hold and operate its assets. The execution and delivery of any Transaction Documents to which the JV is a party and the consummation by the JV of the transactions contemplated herein and therein to which it is a party have been duly and validly authorized by all necessary limited liability company action by the JV, ET, FCV and/or DETG (as the case may be).

4.2 Enforceability. This Agreement constitutes and, upon execution of and delivery by HOLDINGS, GP and MIDSTREAM of the other Transaction Documents to which it is a party, such Transaction Documents will constitute, valid and binding obligations of HOLDINGS, GP and MIDSTREAM, enforceable against such Parties in accordance with their terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium and other similar Laws affecting creditor's rights generally and general principles of equity.

4.3 No Conflicts. The execution, delivery and performance by HOLDINGS, GP and MIDSTREAM of this Agreement, and the execution, delivery and performance by HOLDINGS, GP and MIDSTREAM of the other Transaction Documents to which it is a party and the consummation of the transactions contemplated hereby or thereby, will not:

(a) Provided all of HOLDINGS' Required Consents and Post Closing Consents have been obtained, conflict with, constitute a breach, violation or termination of, give rise to any right of termination, cancellation or acceleration of or result in the loss of any right or benefit under, any agreements to which HOLDINGS, GP, MIDSTREAM or the Entities is a party or by which any of them, the Subject Interests or the Assets are bound;

(b) Conflict with or violate the limited liability company agreements of MIDSTREAM, JV, DETG, FCV, HOLDINGS, GP or ET; and

(c) Provided that all of HOLDINGS' Required Consents and Post Closing Consents have been obtained, violate any Law applicable to HOLDINGS, GP, MIDSTREAM or the Entities or the Assets.

4.4 Consents, Approvals, Authorizations and Governmental Regulations.

(a) Except (i) for Post-Closing Consents, (ii) as set forth in Schedule 4.4 and (iii) as may be required under the HSR Act (the items described in clauses (ii) and (iii) being collectively referred to as the "HOLDINGS' Required Consents"; no order, consent, waiver, permission, authorization or approval of, or exemption by, or the giving of notice to or the registration or filing with any Third Person, is necessary for HOLDINGS, GP or MIDSTREAM to execute, deliver and perform this Agreement or for HOLDINGS, GP or MIDSTREAM to execute, deliver and perform the other Transaction Documents to which it is a party.

(b) Except as set forth in Schedule 4.4, (i), all material permits, licenses, certificates, orders, approvals, authorizations, grants, consents, concessions, warrants, franchises and similar rights and privileges, of all Governmental Authorities required or necessary for the Entities to own and operate its Assets in the places and in the manner currently owned or operated, have been obtained, and are in full force and effect, (ii) HOLDINGS and its Affiliates have received no written notification concerning, and there are no violations that are in existence with respect to the permits and (iii) no Proceeding is pending or threatened with respect to the revocation or limitation of any of the permits. Notwithstanding anything herein to the contrary, the provisions of this Section 4.4(b) shall not relate to or cover any matter relating to or arising out of any Environmental Laws (an "Environmental Matter"), which shall be governed by Section 4.12.

4.5 Taxes. Except as set forth in Schedule 4.5:

(a) JV has not and will not on or prior to the Closing Date, file an election under Treasury Regulation §301.7701-3 to be classified as a corporation for U.S. federal income tax purposes. Since the date of their formation until Closing, DETG, FCV and ET have been and will be business entities that will be disregarded for federal Tax purposes under Treasury Regulation §§301.7701-2 and -3;

(b) Except with respect to ad valorem Taxes for the year in which Closing occurs, all Taxes due and owing or claimed to be due and owing (whether such claim is asserted before or after the Effective Time) from or against any Entity relating to the Assets, or the operation thereof, prior to the Effective Time have been or will be timely paid in full by, for or on behalf or with respect to the Entity owing such Tax;

(c) All withholding Tax and Tax deposit requirements imposed on HOLDINGS, the Entities, and applicable to the Assets, or the operation thereof, for any and all periods or portions thereof ending prior to the Effective Time have been or will be timely satisfied in full by for or on behalf or with respect to the Entity owing such Tax;

(d) All Tax Returns that are required to be timely filed for, by, on behalf of or with respect to the Entities, before the Effective Time have been or will be filed with the appropriate Governmental Authority; all Taxes shown to be due and payable on such Tax Returns have been or will be paid in full by, for or on behalf or with respect to the Entity owing such Tax;

(e) None of the Entities is under Tax audit or Tax examination by any Governmental Authority. There are no Claims now pending or, to the Knowledge of HOLDINGS, threatened against the Entities with respect to any Tax or any matters under discussion with any Governmental Authority relating to any Tax;

(f) None of the Entities (i) has agreed to make, nor is required to make, any adjustment under Section 481 of the Code or any comparable provision of state, local or foreign Law by reason of a change in accounting method or otherwise, and (ii) is a party to or bound by (or will become a party to or bound by) any Tax sharing, Tax indemnity or Tax allocation agreement; and

(g) The JV has made an election under Section 754 of the Code.

4.6 Litigation; Compliance with Laws.

(a) There is no injunction, restraining order or Proceeding pending against HOLDINGS, GP, MIDSTREAM or the Entities that restrains or prohibits the consummation of the transactions contemplated by this Agreement.

(b) Except for the litigation and Claims identified on Schedule 4.6, there is no written Claim, investigation or examination pending, or to the Knowledge of HOLDINGS and GP, threatened, against or affecting the Entities (or their respective assets) before or by any Third Person.

(c) To HOLDINGS' Knowledge, the Assets have been owned and operated in compliance with applicable Laws, except for any non-compliance which has been timely brought into compliance therewith. Notwithstanding anything herein to the contrary, the provisions of this Section 4.6(c) shall not relate to or cover any Environmental Matters, which shall be governed by Section 4.12.

4.7 Contracts. All of the Contracts that are material to the business of the Entities, taken as a whole, are listed on Schedule 1.1(d), with the exception of interests in real property. The Entities are not in default and there is no event or circumstance that with notice, or lapse of time or both, would constitute an event of default by the applicable Entity under the terms of the Contracts. All of the Contracts of the Entities are in full force and effect and to HOLDINGS' Knowledge, no counter-party to any of the Contracts is in default under the terms of such Contracts. Schedule 1.1(d) lists each Contract that:

(a) expressly obligates an Entity to pay an amount of $500,000 (to the 100% interest) or more and has not been fully performed as of the date hereof;

(b) expressly restricts the ability of an Entity to compete or otherwise to conduct its business in any manner or place;

(c) provides for the sale of products or the provision of services (for a term greater than a year) for amounts in excess of $500,000 (to the 100% interest and including outstanding offers or quotes which by acceptance would create such a Contract) and which have not been fully performed as of the date hereof;

(d) provides a right of first refusal or other restrictive right that limits the ability to transfer, sell or assign an interest in an asset or an equity interest in a Person;

(e) is a master agreement, swap, derivative, option, future or similar type Contract or any open agreement or position thereunder;

(f) is with any current or former employee, officer, director or consultant of HOLDINGS or an Entity or their respective Affiliates;

(g) is an inter-company agreement;

(h) is with any labor union or association;

(i) is a partnership or joint venture agreement with a Third Person in which one of HOLDINGS or an Entity or their respective Affiliates is a party or by which any of them are bound;

(j) is an agreement with a consideration in excess of $500,000 (to the 100% interest) by an Entity to purchase or sell any assets (other than inventory in the Ordinary Course of Business), businesses, capital stock or other debt or equity securities of any Person; or

(k) is an agreement with a consideration in excess of $500,000 (to the 100% interest) involving the merger, consolidation, purchase, sale, transfer or other disposition of interests in real property, capital stock or other debt or equity securities of any Person prior to Closing.

4.8 Title to Assets; Intellectual Property. Except for the Permitted Encumbrances, each of the Entities has Defensible Title to those of the Assets that it operates, free and clear of all Liens, and:

(a) none of HOLDINGS or the Entities has received any written notice of infringement, misappropriation or conflict with respect to Intellectual Property from any Person with respect to the ownership, use or operation of the Assets; and

(b) the ownership, use and operation of the Assets have not infringed, misappropriated or otherwise conflicted with any patents, patent applications, patent rights, trademarks, trademark applications, service marks, service mark applications, copyrights, trade names, unregistered copyrights or trade secrets of any other Person.

4.9 Preferential Rights to Purchase. Except as listed in Schedule 4.9, there are no preferential or similar rights to purchase any portion of the Entities or Assets that will be triggered by this Agreement or the transactions contemplated herein.

4.10 Broker's or Finder's Fees. No investment banker, broker, finder or other Person is entitled to any brokerage or finder's fee or similar commission in respect thereof based in any way on agreements, arrangements or understandings made by or on behalf of HOLDINGS or any of its Affiliates.

4.11 Compliance with Property Instruments. To HOLDINGS' Knowledge and except as set forth in Schedule 4.11, (a) all of the instruments creating the Real Property Interests are presently valid, subsisting and in full force and effect; (b) there are no violations, defaults or breaches thereunder, or existing facts or circumstances which upon notice or the passage of time or both will constitute a violation, default or breach thereunder; and (c) the Assets are currently being operated and maintained in compliance with all terms and provisions of the instruments creating the Real Property Interests. None of HOLDINGS or its Affiliates has received or given any written notice of default or claimed default under any such instruments and is not participating in any negotiations regarding any material modifications thereof.

4.12 Environmental Matters. Except as set forth in Schedule 4.12:

(a) to HOLDINGS' Knowledge, HOLDINGS and its Affiliates have not caused or allowed the generation, use, treatment, manufacture, storage, or disposal of Hazardous Materials at, on or from the Assets, except in accordance with all applicable Environmental Laws;

(b) to HOLDINGS' Knowledge, there has been no release of any Hazardous Materials at, on, from or underlying any of the Assets other than such releases that (i) are not required to be reported to a Governmental Authority, (ii) have been reported to the appropriate Governmental Authority or (iii) were in compliance with applicable Environmental Laws;

(c) to HOLDINGS' Knowledge, the Entities have secured all permits required under Environmental Laws for the ownership, use and operation of the Assets and the Entities are in compliance with such permits;

(d) HOLDINGS and its Affiliates have not received written inquiry or notice of any actual or threatened Claim related to or arising under any Environmental Law relating to the Assets;

(e) none of HOLDINGS or the Entities is currently operating or required to be operating any of the Assets under any compliance order, a decree or agreement, any consent decree or order, or corrective action decree or order issued by or entered into with any Governmental Authority under any Environmental Law or any Law regarding health or safety in the work place;

(f) to HOLDINGS' Knowledge, the Entities have owned, used and operated the Assets in compliance with Environmental Laws, except for any non-compliance which has been remediated and brought into compliance with Environmental Laws; and

(g) to HOLDINGS' Knowledge, none of the off-site locations where Hazardous Materials from any of the Assets have been transported, stored, treated, recycled, disposed of or released has been designated as a facility that is subject to a Claim under any Environmental Laws.

4.13 Employee Matters. At no time prior to the Effective Time will the Entities have had any employees.

4.14 Benefit Plan Liabilities. At no time prior to the Effective Time will the Entities have maintained any Benefit Plans. At the Effective Time, the Entities shall have no liability with respect to any Benefit Plans.

4.15 No Foreign Person. HOLDINGS is not a "foreign person" as defined in Section 1445 of the Code and in any regulations promulgated thereunder.

4.16 Capitalization of the Subject Interests.

(a) The Subject Interests (i) constitute 25.1% of the outstanding ownership interests in the JV, (ii) were duly authorized, validly issued, fully paid and non-assessable and (iii) were not issued in violation of any pre-emptive rights.

(b) HOLDINGS and GP, as applicable, has good and valid title to the Subject Interests conveyed by each of them and, except as provided or created by its limited liability company agreement or other organizational or governance documents, the Securities Act or applicable securities Laws, the Subject Interests are free and clear of any (i) restrictions on transfer, Taxes, Liens, Claims, or Proceedings or (ii) encumbrances, options, warrants, purchase rights, contracts, commitments, equities or demands to the extent any of the same contain or create any right to acquire all or any right in or to the Subject Interests.

(c) There are no existing rights, agreements or commitments of any character obligating the Entities to issue, transfer or sell any additional ownership rights or interests or any other securities (debt, equity or otherwise) convertible into or exchangeable for such ownership rights or interests or repurchase, redeem or otherwise acquire any such interest.

4.17 Subsidiaries and Other Equity Interests. As of Closing, the JV will not have any Subsidiaries or own, directly or indirectly, any equity interest in any other Person except the limited liability company interests listed on Schedule 4.17.

4.18 Bank Accounts. Except as set forth on Schedule 4.18, FCV, DETG and ET (and as of Closing, the JV), have no accounts or safe-deposit boxes with banks, trust companies, savings and loan associations, or other financial institutions.

4.19 [Reserved].

4.20 Investment Intent. HOLDINGS and GP is acquiring the Units for its own account, and not with a view to, or for sale in connection with, the distribution thereof in violation of state or federal Law. HOLDINGS and GP acknowledges that the Units have not been registered under the Securities Act or the securities Laws of any state and neither HOLDINGS nor GP has any obligation or right to register the Units except as set forth in the Limited Partnership Agreement. Without such registration, the Units may not be sold, pledged, hypothecated or otherwise transferred unless it is determined that registration is not required. HOLDINGS, itself or through its officers, employees or agents, has sufficient knowledge and experience in financial and business matters to be capable of evaluating the merits and risks of an investment such as an investment in the Units, and HOLDINGS, either alone or through its officers, employees or agents, has evaluated the merits and risks of the investment in the Units.

4.21 Financial Statements; Internal Controls; Undisclosed Liabilities. To HOLDINGS' Knowledge:

(a) Schedule 4.21 sets forth a true and complete copy of the [unaudited] consolidated balance sheet as of December 31, 2008, and the unaudited consolidated statement of changes in MLP's equity, the unaudited consolidated statement of operations, and unaudited consolidated statement of cash flow for the twelve months ended December 31, 2008; and the audited consolidated balance sheet as of December 31, 2007, and the audited consolidated statement of changes in MLP's equity, the audited consolidated statement of operations, and audited consolidated statement of cash flow for the twelve months ended December 31, 2007 for the business of the JV (the "Annual Financial Statements"). The Annual Financial Statements have been prepared in accordance with the requirements of Regulation S-X adopted by the SEC.

(b) There are no liabilities or obligations of the JV (whether known or unknown and whether accrued, absolute, contingent or otherwise) and there are no facts or circumstances that would reasonably be expected to result in any such liabilities or obligations, other than (i) liabilities or obligations disclosed, reflected or reserved against in the Annual Financial Statements, and (ii) current liabilities incurred in the Ordinary Course of Business since December 31, 2008.

4.22 No Other Representations or Warranties; Schedules. HOLDINGS makes no other express or implied representation or warranty with respect to the Entities or any of their respective Affiliates, the Assets or the transactions contemplated by this Agreement, and disclaims any other representations or warranties. The disclosure of any matter or item in any schedule to this Agreement shall not be deemed to constitute an acknowledgment that any such matter is required to be disclosed.

ARTICLE V
REPRESENTATIONS AND WARRANTIES OF MLP

MLP hereby represents and warrants to HOLDINGS:

5.1 Organization, Good Standing, and Authorization. MLP is a limited partnership duly formed, validly existing and in good standing under the Laws of the State of Delaware. MLP has all requisite limited partnership power and authority to enter into and perform this Agreement and the Transaction Documents to which it is a party, to perform its obligations hereunder and thereunder and to carry out the transactions contemplated herein and therein. The execution and delivery of this Agreement and the Transaction Documents to which it is a party and the consummation by MLP of the transactions contemplated herein have been duly and validly authorized by all necessary limited partnership action by MLP. This Agreement has been duly executed and delivered by MLP.

5.2 Enforceability. This Agreement constitutes, and upon execution and delivery of the Transaction Documents to which MLP is a party, such Transaction Documents will constitute, valid and binding obligations of MLP, enforceable against MLP in accordance with their terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium and other similar Laws affecting creditor's rights generally and general principles of equity.

5.3 No Conflicts. The execution, delivery and performance by MLP of this Agreement and the Transaction Documents and the consummation of the transactions contemplated hereby or thereby, will not:

(a) provided that any MLP Required Consents and Post-Closing Consents have been obtained, conflict with, constitute a breach, violation or termination of, give rise to any right of termination, cancellation or acceleration of or result in the loss of any right or benefit under, any agreement to which MLP is a party;

(b) conflict with or violate the Limited Partnership Agreement or result in the creation of a Lien on the Units; or

(c) provided that all of the MLP Required Consents and Post Closing Consents have been obtained, violate any Law applicable to MLP.

5.4 Consents, Approvals, Authorizations and Governmental Regulations. Except (i) for Post-Closing Consents, and (ii) as set forth in Schedule 5.4 and (iii) as may be required under the HSR Act (the items described in clauses (ii) and (iii) being collectively referred to as the "MLP Required Consents"), no order, consent, waiver, permission, authorization or approval of, or exemption by, or the giving of notice to or registration or filing with, any Third Person, is necessary for MLP to execute, deliver and perform this Agreement or the Transaction Documents to which it will be a party.

5.5 Litigation. There is no injunction, restraining order or Proceeding pending against MLP that restrains or prohibits the consummation of the transactions contemplated by this Agreement.

5.6 Independent Investigation. MLP is knowledgeable in the business of owning and operating natural gas and natural gas liquids facilities and has had access to the Assets, the representatives of HOLDINGS and its Affiliates, and to the records of HOLDINGS and its Affiliates with respect to the Assets. MLP ACKNOWLEDGES THAT THE ASSETS ARE IN THEIR “AS IS, WHERE IS” CONDITION AND STATE OF REPAIR, AND WITH ALL FAULTS AND DEFECTS, AND THAT, EXCEPT AS EXPRESSLY SET OUT IN THIS AGREEMENT, HOLDINGS HAS MADE NO REPRESENTATION OR WARRANTY OF ANY KIND OR NATURE, EXPRESS, IMPLIED OR STATUTORY, INCLUDING, BUT NOT LIMITED TO, WARRANTIES OF MARKETABILITY, QUALITY, CONDITION, CONFORMITY TO SAMPLES, MERCHANTABILITY, AND/OR FITNESS FOR A PARTICULAR PURPOSE, ALL OF WHICH ARE EXPRESSLY DISCLAIMED BY HOLDINGS AND EXCEPT AS SET FORTH IN THIS AGREEMENT, WAIVED BY MLP. MLP FURTHER ACKNOWLEDGES THAT: (I) THE ASSETS HAVE BEEN USED FOR NATURAL GAS AND NATURAL GAS LIQUIDS OPERATIONS AND PHYSICAL CHANGES IN THE ASSETS AND IN THE LANDS BURDENED THEREBY MAY HAVE OCCURRED AS A RESULT OF SUCH USES; (II) THE ASSETS MAY INCLUDE BURIED PIPELINES AND OTHER EQUIPMENT, THE LOCATIONS OF WHICH MAY NOT BE KNOWN BY HOLDINGS OR READILY APPARENT BY A PHYSICAL INSPECTION OF THE ASSETS OR THE LANDS BURDENED THEREBY; (III) MLP SHALL HAVE INSPECTED PRIOR TO CLOSING, OR SHALL BE DEEMED TO HAVE WAIVED ITS RIGHTS TO INSPECT, THE ASSETS AND THE ASSOCIATED PREMISES, AND SATISFIED ITSELF AS TO THEIR PHYSICAL AND ENVIRONMENTAL CONDITION, AND THAT MLP SHALL, SUBJECT TO THE OTHER PROVISIONS OF THIS AGREEMENT, ACCEPT ALL OF THE SAME IN THEIR “AS IS, WHERE IS” CONDITION AND STATE OF REPAIR, AND WITH ALL FAULTS AND DEFECTS, INCLUDING, BUT NOT LIMITED TO, THE PRESENCE OF MAN-MADE MATERIAL FIBERS AND THE PRESENCE, RELEASE OR DISPOSAL OF HAZARDOUS MATERIALS. EXCEPT AS EXPRESSLY SET OUT IN THIS AGREEMENT, HOLDINGS MAKES NO REPRESENTATION OR WARRANTY, EXPRESS, IMPLIED OR STATUTORY, AS TO (A) THE ACCURACY OR COMPLETENESS OF ANY DATA OR RECORDS DELIVERED TO MLP WITH RESPECT TO THE INTERESTS, INCLUDING, WITHOUT LIMITATION, ANY DESCRIPTION OF THE INTERESTS, PRICING ASSUMPTIONS, QUALITY OR QUANTITY OF THE INTERESTS, FREEDOM FROM PATENT OR TRADEMARK INFRINGEMENT OR (B) FUTURE VOLUMES OF HYDROCARBONS OR OTHER PRODUCTS TRANSPORTED, TREATED, STORED OR PROCESSED THROUGH OR AT THE ASSETS. With respect to any projection or forecast delivered by or on behalf of HOLDINGS or its Affiliates to MLP, MLP acknowledges that (i) there are uncertainties inherent in attempting to make such projections and forecasts, (ii) MLP is familiar with such uncertainties, (iii) MLP is taking full responsibility for making its own evaluation of the adequacy and accuracy of all such projections and forecasts furnished to MLP and (iv) MLP will not have a claim against HOLDINGS or any of its advisors or Affiliates with respect to such projections or forecasts.

5.7 Broker's or Finder's Fees. No investment banker, broker, finder or other Person is entitled to any brokerage or finder's fee or similar commission in respect thereof based in any way on agreements, arrangements or understandings made by or on behalf of MLP or any of its Affiliates which is, or following the Closing would be, an obligation of HOLDINGS or any of its Affiliates.

5.8 Investment Intent. MLP is acquiring the Subject Interests for its own account, and not with a view to, or for sale in connection with, the distribution thereof in violation of state or federal Law. MLP acknowledges that the Subject Interests have not been registered under the Securities Act or the securities Laws of any state and neither HOLDINGS nor any of its Affiliates has any obligation to register the Subject Interests. Without such registration, the Subject Interests may not be sold, pledged, hypothecated or otherwise transferred unless it is determined that registration is not required. MLP, itself or through its officers, employees or agents, has sufficient knowledge and experience in financial and business matters to be capable of evaluating the merits and risks of an investment such as an investment in the Subject Interests, and MLP, either alone or through its officers, employees or agents, has evaluated the merits and risks of the investment in the Subject Interests.

5.9 Available Funds. MLP will have at Closing, sufficient cash to enable it to make payment in immediately available funds of the cash amount specified in Section 2.2(ii) when due and any other amounts to be paid by it hereunder.

ARTICLE VI
COVENANTS AND ACCESS

6.1 Conduct of Business. HOLDINGS and MIDSTREAM each covenants and agrees that from and after the execution of this Agreement and until the Closing:

(a) Without the prior written consent of MLP, (i) HOLDINGS will not, and will not permit the Entities to sell, transfer, assign, convey or otherwise dispose of any Assets other than (A) the transfer of the Excluded Assets; (B) the sale of inventory in the Ordinary Course of Business or (C) the sale or other disposition of equipment or other Personal Property which is replaced with equipment or other Personal Property of comparable or better value and utility; (ii) except for the existing Capital Projects, modify in any respect the East Texas System that will require a capital expenditure in excess of $1,000,000 (as to the 100% interest); (iii) make any adverse change in its sales, credit or collection terms and conditions relating to the Assets; (iv) do any act or omit to do any act which will cause a material breach in any Contract; or (v) unless disputed in good faith, fail to pay when due all amounts owed under the Contracts;

(b) HOLDINGS will not allow the Entities to create or permit the creation of any Lien on any Asset other than Permitted Encumbrances;

(c) If HOLDINGS becomes aware of any event or development that it reasonably believes is likely to cause a material breach or default hereunder or to have a Material Adverse Effect, it will give prompt written notice to MLP; and

(d) HOLDINGS will and will cause the Entities to:

(i) maintain and operate the Assets in the Ordinary Course of Business, including regular scheduled maintenance plans and capital expenditures, and pay or cause to be paid all costs and expenses in connection therewith when due;

(ii) carry on its business in respect of the Assets in substantially the same manner as it has heretofore;

(iii) use reasonable efforts to preserve its business in respect of the Assets intact, to keep available the services of the employees involved in the conduct of such business and to preserve the goodwill of customers having business relations with the applicable Entities in respect of the Assets, in each case, in all material respects;

(iv) not abandon any of the Assets or liquidate, dissolve, recapitalize or otherwise wind up its business;

(v) comply in all material respects with all of the rules, regulations and orders of any Governmental Authority applicable to the Assets;

(vi) timely file, properly and accurately make in all material respects all reports and filings required to be filed with the appropriate Governmental Authority; and

(vii) pay all Taxes with respect to the Assets which come due and payable prior to the Closing Date;

(viii) not make, amend or revoke any material election with respect to Taxes;

(ix) not amend its organizational documents;

(x) not make any material change in any method of accounting or accounting principles, practices or policies, other than those required by GAAP;

(xi) not issue or sell any equity interests, notes, bonds or other securities or incur, assume or guarantee any indebtedness for borrowed money, or any option, warrant or right to acquire same;

(xii) not (A) merge or consolidate with any Person; or (B) make any loan to any Person (other than extensions of credit to customers in the Ordinary Course of Business and inter-company loans under DCP Midstream, LLC’s cash management system); and

(xiii) maintain in full force and effect insurance policies covering the Assets.

(xiv) with respect to the Contracts, not enter into any financial derivatives that would be Assumed Obligations unless the same are in compliance with MIDSTREAM's risk management guidelines.

6.2 Casualty Loss.

(a) HOLDINGS shall promptly notify MLP of any Casualty Loss of which HOLDINGS becomes aware prior to the Closing. If a Casualty Loss, other than the East Texas Casualty Incident (addressed in (c) below), occurs and such Casualty Loss would reasonably be expected to have a Material Adverse Effect (a "Material Casualty Loss"), HOLDINGS shall have the right to extend the Closing Date for up to forty-five (45) days for the purpose of repairing or replacing the Assets destroyed or damaged by the Material Casualty Loss to the reasonable satisfaction of MLP. If HOLDINGS does not repair or replace the Assets destroyed or damaged by the Material Casualty Loss prior to the Closing to the reasonable satisfaction of MLP and the Parties are unable to agree on a value to compensate MLP for the Material Casualty Loss, MLP may terminate this Agreement upon fifteen (15) days written notice to HOLDINGS.

(b) If this Agreement is not terminated by MLP as provided in subsection (a), MLP's sole remedy with respect to any Casualty Loss in respect of Assets which are not repaired or replaced prior to the Closing to the reasonable satisfaction of MLP (but only to the extent not reflected in Net Working Capital) is to accept a value estimated by HOLDINGS and agreed to by MLP to be equal to 25.1% of the cost to repair or replace the Assets of any Entity affected by the Casualty Loss, as applicable; provided that (A) if the Parties cannot agree, then the Closing shall occur and either Party may submit the determination of the costs of the Casualty Loss for resolution pursuant to Section 11.8; and (B) with respect to any Casualty Loss, any insurance, condemnation or taking proceeds shall become 25.1% the sole property of HOLDINGS and GP, and 74.9% the sole property of the JV, to be managed pursuant to the terms of the JV LLC Agreement, and each Party shall execute such assignments, releases, resolutions or other documents as may be necessary to vest such proceeds in the persons and percentages set forth above.

(c) As to the East Texas Casualty Incident, HOLDINGS shall pay the costs and expenses attributable to the Subject Interests as necessary to repair and replace the damaged Facilities caused by the East Texas Casualty Incident prior to the Closing, to the reasonable satisfaction of MLP. In consideration of HOLDINGS' obligation to pay the costs and expenses attributable to the Subject Interests to repair and replace the Facilities damaged by the East Texas Casualty Incident, any and all insurance proceeds attributable to the Subject Interests that may be payable to the JV, MLP or any of their Affiliates in respect of any claims made regarding the East Texas Casualty Incident (including without limitation, property loss policy proceeds and business interruption policy proceeds) shall be the sole property of HOLDINGS, and each Party shall execute such assignments, releases, resolutions or other documents as may be necessary to vest such proceeds in the persons and percentages set forth above. HOLDINGS shall have the right to extend the Closing Date for up to forty-five (45) days for the purpose of repairing or replacing the Facilities destroyed or damaged by the East Texas Casualty Incident. If HOLDINGS does not repair or replace the Assets destroyed or damaged by the East Texas Casualty

Incident prior to the Closing to the reasonable satisfaction of MLP, and the Parties are unable to agree on a value to compensate MLP for the East Texas Casualty Incident's effect on the Subject Interests, then MLP may terminate this Agreement upon fifteen (15) days written notice to HOLDINGS.

6.3 Access, Information and Access Indemnity.

(a) Prior to Closing, HOLDINGS will make available at HOLDINGS' offices to MLP and MLP's authorized representatives for examination as MLP may reasonably request, all Records; provided, however, such material shall not include (i) any proprietary data which relates to another business of HOLDINGS or its Affiliates and is not primarily used in connection with the continued ownership, use or operation of the Assets, (ii) any information subject to Third Person confidentiality agreements for which a consent or waiver cannot be secured by HOLDINGS or its Affiliates after reasonable efforts, or (iii) any information which, if disclosed, would violate an attorney-client privilege or would constitute a waiver of rights as to attorney work product or attorney-client privileged communications.

(b) Subject to subsection (a) above, HOLDINGS shall permit MLP and MLP's authorized representatives to consult with employees of HOLDINGS and its Affiliates during the business hours of 8:00 a.m. to 5:00 p.m. (local time), Monday through Friday and to conduct, at MLP's sole risk and expense, inspections and inventories of the Assets and to examine all Records over which HOLDINGS and its Affiliates have control. HOLDINGS shall also coordinate, in advance, with MLP to allow site visits and inspections at the field sites on Saturdays unless operational conditions would reasonably prohibit such access.

(c) MLP SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD THE HOLDINGS' INDEMNITEES HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS AND LOSSES OCCURRING ON OR TO THE ASSETS CAUSED BY THE ACTS OR OMISSIONS OF MLP, MLP'S AFFILIATES OR ANY PERSON ACTING ON MLP'S OR ITS AFFILIATES' BEHALF IN CONNECTION WITH ANY DUE DILIGENCE CONDUCTED PURSUANT TO OR IN CONNECTION WITH THIS AGREEMENT PRIOR TO CLOSING, INCLUDING ANY SITE VISITS AND ENVIRONMENTAL SAMPLING; PROVIDED, HOWEVER, THE FOREGOING OBLIGATION OF MLP SHALL NOT APPLY WITH RESPECT TO ANY ENVIRONMENTAL CONDITIONS TO THE EXTENT EXISTING PRIOR TO THE CONDUCT OF SUCH DUE DILIGENCE WHICH ARE DISCOVERED DURING SUCH DUE DILIGENCE. MLP shall comply in all material respects with all rules, regulations, policies and instructions issued by HOLDINGS, GP or any Third Person operator regarding MLP's actions prior to Closing while upon, entering or leaving any property included in the Assets, including any insurance requirements that HOLDINGS may impose on contractors authorized to perform work on any property owned or operated by HOLDINGS.

6.4 Regulatory Filings; Hart-Scott-Rodino Filing.

(a) MLP and HOLDINGS will take all commercially reasonable actions necessary or desirable, and proceed diligently and in good faith and use all commercially reasonable efforts, as promptly as practicable to obtain all consents, approvals or actions of, to make all filings with, and to give all notices to, Governmental Authorities required to accomplish the transactions contemplated by this Agreement; provided, however, that the cost to obtain Post-Closing Consents shall be borne by MLP.

(b) The Parties shall make any filings required under the HSR Act on or prior to five (5) days after the date of this Agreement and provide such information to the FTC as is required in connection with the HSR Act as soon as practicable after a request therefore.

(c) Notwithstanding any provision herein to the contrary, each of the Parties will (i) use reasonable efforts to comply as expeditiously as possible with all lawful requests of Governmental Authorities for additional information and documents pursuant to the HSR Act, (ii) not (A) extend any waiting period under the HSR Act or (B) enter into any voluntary agreement with any Governmental Authority not to consummate the transactions contemplated by this Agreement, except with the prior consent of the other Party, and (iii) cooperate with each other and use reasonable efforts to obtain the requisite approval of the FTC and DOJ; provided, however, that the Parties are not obligated to accept any conditional approval or divest any of the Assets or any of their properties.

(d) MLP will be responsible for paying the filing fees required with respect to any filing under the HSR Act.

6.5 Limitation on Casualty Losses and Other Matters. Notwithstanding any provision herein to the contrary, if either HOLDINGS or MLP reasonably determines that the anticipated aggregate value of any Casualty Losses and a good faith estimate of HOLDINGS' liability with respect to breaches of representations and warranties of which either HOLDINGS or MLP has provided notice to the other prior to Closing, exceeds $2,500,000, then such Party shall provide written notice to the other of such determination together with the notifying Party's calculations of the estimated costs, payments, reductions and liabilities supporting such determination. Notwithstanding Section 9.1(c), upon the other Party's receipt of such notice, the Party receiving the notice shall have the right to terminate this Agreement at any time prior to Closing upon ten (10) days written notice to the other Party.

6.6 Supplements to Exhibits and Schedules. HOLDINGS may, from time to time, by written notice to MLP at any time prior to the Closing Date, supplement or amend the Exhibits and Schedules to correct any matter that would constitute a breach of any representation or warranty of HOLDINGS herein contained. MLP shall have a minimum of five (5) Business Days to review such supplement or amendment and the Closing shall be extended as required to allow MLP to do so; provided, however, if MLP reasonably determines that any individual new disclosure item set forth in any such supplement or amendment would increase the amount of the Assumed Obligations by more than $50,000, then MLP shall notify HOLDINGS of such determination together with MLP's calculations of such increase in the amount of the Assumed Obligations. Promptly upon HOLDINGS' receipt of such written notice, the Parties shall endeavor in good faith to agree to a value to be paid by HOLDINGS to MLP therefor or other mutually agreeable remedy to address the matters which are the subject of such supplement(s) and amendment(s) to the Exhibits and Schedules. If within fifteen (15) days of HOLDINGS' receipt of such written notice, the Parties have not agreed to a value to be paid by HOLDINGS to MLP therefore or another mutually agreeable remedy, MLP shall have the right to terminate this Agreement at any time during the five (5) Business Days following the expiration of such fifteen (15) day period by provision of written notice to HOLDINGS. Notwithstanding any other provision hereof, if the Closing occurs, any such supplement or amendment will be effective to cure and correct for all purposes any breach of any representation or warranty that would have existed if such supplement or amendment had not been made.

6.7 Preservation of Records. For a period of seven (7) years after the Closing Date, the Party in possession of the originals of the Records will retain such Records at its sole cost and expense and will make such Records available to the other Party to the extent pertaining to such other Parties' obligations hereunder upon reasonable notice for inspection and/or copying, at the expense of the requesting Party, at the headquarters of the Party in possession (or at such other location in the United States as the Party in possession may designate in writing to the other Party) at reasonable times and during regular office hours. MLP agrees that HOLDINGS may retain a copy of the Records to the extent such Records pertain to its obligations hereunder.

6.8 [Reserved]

6.9 Capital Projects.

(a) One or more of the Entities is undertaking the ongoing construction of the natural gas gathering systems, inlet liquid handling facilities, and flare systems described by open AFE on Schedule 6.9 (the "Capital Projects"). HOLDINGS or its Affiliates shall continue to pursue the construction, on the JV's behalf, of the Capital Projects through the Effective Time, and, from and after the Effective Time until the third anniversary thereof, HOLDINGS will reimburse the JV on a monthly basis solely for those costs and expenses incurred by the JV to complete the Capital Projects that are attributable to the Subject Interests.

(b) Notwithstanding anything to the contrary set forth in this Agreement, any other capital expenditures for projects or maintenance capital (but excluding capital expenditures related to the Capital Projects or Casualty Losses (collectively, the "New Capital Projects") incurred between the Execution Date and Closing and attributable to the Subject Interests shall be reimbursed by MLP to HOLDINGS as provided in Section 2.2.

(c) Upon Closing, HOLDINGS' and its Affiliates' obligations for the payment or reimbursement of costs and expenses with respect to the East Texas Inlet Liquid Handling Facilities (as such obligations are outlined in Section 6.9 of the Prior Contribution Agreement) shall terminate and be deemed fully satisfied, completed, and superseded, and neither HOLDINGS nor the MLP shall have any further obligation, duty or responsibility to make any payment or perform any duty, obligation or action under Section 6.9(c) of the Prior Contribution Agreement from and after the Closing.

6.10 [Reserved]

6.11 Tax Covenants; Preparation of Tax Returns. The MLP shall cause the JV to prepare and file, or cause to be prepared and filed, all Tax Returns required to be filed by the Entities and also shall cause the JV to cause the Entities to pay the Taxes shown to be due thereon; provided, however, that MIDSTREAM shall promptly reimburse the MLP for the portion of such Tax attributable to the Subject Interests that relates to a Pre-Closing Tax Period, to the extent not accrued in the Final Settlement Statement. MIDSTREAM shall furnish to the MLP all information and records reasonably requested by the MLP for use in preparation of any Tax Returns. The Parties shall cause the MLP to allow MIDSTREAM to review, comment upon and reasonably approve without undue delay any Tax Return at any time during the twenty (20) day period immediately preceding the filing of such Tax Return.

6.12 Financial Statements and Financial Records. HOLDINGS shall consent to the inclusion or incorporation by reference of the Annual Financial Statements in any registration statement, report or other document of MLP or any of its Affiliates to be filed with the SEC in which MLP or such Affiliate reasonably determines that the SEC Financial Statements are required to be included or incorporated by reference to satisfy any rule or regulation of the SEC or to satisfy relevant disclosure obligations under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended. HOLDINGS shall cause its auditors to consent to the inclusion or incorporation by reference of its audit opinion with respect to the Annual Financial Statements in any such registration statement, report or other document and, in connection therewith, HOLDINGS shall execute and deliver to its auditors such representation letters, in form and substance customary for representation letters provided to external audit firms by management of the company whose financial statements are the subject of an audit, as may be reasonably requested by its auditors.

ARTICLE VII
CONDITIONS TO CLOSING

7.1 HOLDINGS'/GP's Conditions. The obligation of HOLDINGS and GP to close is subject to the satisfaction of the following conditions, any of which may be waived in HOLDINGS' sole discretion:

(a) The representations of MLP contained in Article V shall be true, in all material respects (or, in the case of representations or warranties that are already qualified by a materiality standard, shall be true in all respects) on and as of Closing.

(b) MLP shall have performed in all material respects the obligations, covenants and agreements of MLP contained herein.

(c) There is no injunction, restraining order or Proceeding pending against HOLDINGS or the Entities that restrains or prohibits the consummation of the transactions contemplated by this Agreement.

(d) All of HOLDINGS' Required Consents, MLP's Required Consents, consents under the Real Property Interests, Contracts and Permits and consents or approvals under the HSR Act (or expiration of the waiting period) shall have been obtained.

(e) MLP shall have made all deliveries in accordance with Section 8.2(b).

7.2 MLP's Conditions. The obligation of MLP to close is subject to the satisfaction of the following conditions, any of which may be waived in its sole discretion:

(a) The representations of HOLDINGS contained in Article IV shall be true, in all material respects (or in the case of representations or warranties that are already qualified by a materiality standard, shall be true in all respects) on and as of the Closing.

(b) HOLDINGS shall have performed, in all material respects, the obligations, covenants and agreements of HOLDINGS contained herein.

(c) There is no injunction, restraining order or Proceeding pending against HOLDINGS or the Entities that restrains or prohibits the consummation of the transactions contemplated by this Agreement.

(d) All of HOLDINGS' Required Consents, MLP's Required Consents, consents under the Real Property Interests, Contracts and Permits and consents or approvals under the HSR Act (or expiration of the waiting period) shall have been obtained.

(e) There shall have been no events or occurrences that could reasonably be expected to have a Material Adverse Effect.

(f) HOLDINGS shall have delivered all documents in accordance with Section 8.2(a).

(g) MLP shall have received audited financial statements for the JV for the year ended December 31, 2008, that are satisfactory to MLP in its sole discretion.

7.3 Exceptions. Notwithstanding the provisions of Sections 7.1(a) and (b) and 7.2(a) and (b), no Party shall have the right to refuse to close the transaction contemplated hereby by reason of this Article VII unless (a) in the case of HOLDINGS and GP , the sum of all representations of MLP contained in Article V which are not true and all obligations, covenants and agreements which MLP has failed to perform, would reasonably be expected to have a Material Adverse Effect, and (b) in the case of MLP, the sum of all representations of HOLDINGS and GP contained in Article IV which are not true and all obligations, covenants and agreements which HOLDINGS and GP has failed to perform, would reasonably be expected to have a Material Adverse Effect.

ARTICLE VIII
CLOSING

8.1 Time and Place of Closing. The consummation of the transactions contemplated by this Agreement (the "Closing") shall take place in the offices of MIDSTREAM in Denver, Colorado at (a) a pre-closing at 9:00 a.m. on March 31, 2009 (at which the Transaction Documents and Officer's Certificates will be executed) and (b) a final closing at 9:00 a.m. Denver time on April 1, 2009 (unless such date is otherwise extended by either HOLDINGS or MLP as permitted hereunder); or on the last day of the month following the receipt of the consents required by Sections 7.1(d) and 7.2(d) (if later than the foregoing specified date of Closing), or such other time and place as the Parties agree to in writing (the "Closing Date"), and shall be effective as of the Effective Time.

8.2 Deliveries at Closing. At the Closing,

(a) HOLDINGS and GP, as applicable, will execute and deliver or cause to be executed and delivered to MLP:

(i) Each of the Transaction Documents to which HOLDINGS, GP or Affiliates are a party;

(ii) Certificates of a corporate officer or other authorized person dated the Closing Date, certifying on behalf of HOLDINGS and GP that the conditions in Sections 7.2(a) and (b) have been fulfilled.

(b) MLP will execute and deliver or cause to be executed and delivered to HOLDINGS and GP:

(i) Each of the Transaction Documents to which MLP or MLP's Affiliates are a party;

(ii) A certificate of a corporate officer or other authorized person dated the Closing Date certifying on behalf of MLP that the conditions in Sections 7.1(a) and (b) have been fulfilled;

(iii) Certificates for Class D Units, determined in accordance with Sections 2.2 and 2.3;

(iv) A wire transfer to HOLDINGS and GP of the amounts due with respect to the Total Net Working Capital and New Capital Projects (as set forth in the Preliminary Settlement Statement).

ARTICLE IX
TERMINATION

9.1 Termination. This Agreement may be terminated and the transactions contemplated hereby abandoned as follows:

(a) HOLDINGS and MLP may elect to terminate this Agreement at any time prior to the Closing by mutual written consent thereof;

(b) Either HOLDINGS or MLP by written notice to the other may terminate this Agreement if the Closing shall not have occurred on or before June 1, 2009;

provided, however, that neither Party may terminate this Agreement if such Party is at such time in material breach of any provision of this Agreement;

(c) HOLDINGS and MLP may each terminate this Agreement at any time on or prior to the Closing if either MLP, on the one hand, or HOLDINGS, on the other hand, shall have materially breached any representations, warranties or covenants thereof herein contained with the sum of such breach or breaches reasonably expected to have a Material Adverse Effect and the same is not cured within thirty (30) days after receipt of written notice thereof from the applicable non-breaching Party; provided, however, that neither Party may terminate this Agreement if such Party is at such time in material breach of any representations, warranties or covenants of such Party; and

(d) In addition to the foregoing, any Party may terminate this Agreement to the extent such termination is expressly authorized by another provision of this Agreement.

9.2 Effect of Termination Prior to Closing. If Closing does not occur as a result of any Party exercising its right to terminate pursuant to Section 9.1, then no Party shall have any further rights or obligations under this Agreement, except that (i) nothing herein shall relieve any Party from any liability for any willful breach of this Agreement, and (ii) the provisions of Section 6.3(c) and Article XI shall survive any termination of this Agreement.

ARTICLE X
INDEMNIFICATION

10.1 Indemnification by MLP. Effective upon Closing, MLP shall defend, indemnify and hold harmless HOLDINGS and its Affiliates, and all of its and their directors, officers, employees, partners, members, contractors, agents, and representatives (collectively, the "HOLDINGS Indemnitees") from and against any and all Losses asserted against, resulting from, imposed upon or incurred by any of the HOLDINGS Indemnitees as a result of or arising out of:

(a) the breach of any of the representations or warranties under Article V;

(b) the breach of any covenants or agreements of MLP contained in this Agreement; and

(c) to the extent that HOLDINGS is not required to indemnify any of the MLP Indemnitees pursuant to Section 10.2, the Assumed Obligations.

10.2 Indemnification by HOLDINGS. Effective upon Closing, HOLDINGS shall defend, indemnify and hold harmless MLP and its Affiliates, and all of its and their directors, officers, employees, partners, members, contractors, agents, and representatives (collectively, the "MLP Indemnitees") from and against any and all Losses asserted against, resulting from, imposed upon or incurred by any of the MLP Indemnitees as a result of or arising out of:

(a) the breach of any of the representations or warranties under Article IV (other than Sections 4.1, 4.2, 4.16 and 4.17),

(b) subject to Section 6.9, to the extent not accounted for in the Final Settlement Statement, Claims asserted within one (1) year after Closing to the extent related to underpayment of trade payables for periods prior to the Effective Time;

(c) with respect to the Former UP Fuels Properties, Claims by Governmental Authorities asserted within two (2) years after Closing to the extent related to fines and penalties for periods between April 1, 1999 and Closing;

(d) with respect to the Former Gulf South Properties, Claims by Governmental Authorities asserted within two (2) years after Closing to the extent related to fines and penalties for periods between March 31, 2005 and Closing;

(e) to the extent and subject to any limitations provided therein, any matters set forth on Schedule 10.2(e);

(f) the breach of any of the representations or warranties under Sections 4.1, 4.2, 4.16 and 4.17 or the covenants or agreements of HOLDINGS contained in this Agreement; and

(g) any Reserved Liabilities.

10.3 Deductibles, Caps, Survival and Certain Limitations.

(a) Subject to this Section 10.3, all representations, warranties, covenants and indemnities made by the Parties in this Agreement or pursuant hereto shall survive the Closing as hereinafter provided, and shall not be merged into any instruments or agreements delivered at Closing.

(b) With respect to the obligations of HOLDINGS:

(i) under Sections 10.2(a) or (b), none of the MLP Indemnitees shall be entitled to assert any right to indemnification after one (1) year from the Closing;

(ii) under Section 10.2(c) or (d), none of the MLP Indemnitees shall be entitled to assert any right to indemnification after two (2) years from the Closing;

(iii) under Section 10.2(a), none of the MLP Indemnitees shall be entitled to assert any right to indemnification unless the individual claim or series of related claims which arise out of substantially the same facts and circumstances exceeds $50,000 ("Qualified Claims");

(iv) under Section 10.2(a), none of the MLP Indemnitees shall be entitled to assert any right to indemnification unless Qualified Claims for which indemnity is only provided under Section 10.2(a) shall in the aggregate exceed $450,000 and then only to the extent that all such Qualified Claims exceed said amount;

(v) under Section 10.2(a), none of the MLP Indemnitees shall be entitled to indemnification for any amount in excess of $4,500,000; and

(vi) Any indemnification or payment obligations of HOLDINGS under Section 10.2 resulting from HOLDINGS' breach of its representations, warranties, covenants or agreements, shall be limited to Losses that are attributable to the Subject Interests or to the transactions pursuant to which MLP acquires the Subject Interests under this Agreement, and MLP shall have no right to assert any claim under this Agreement related to the 25% member interest in the JV that was acquired under the Prior Contribution Agreement. Notwithstanding the foregoing, the indemnification rights of MLP and any MLP Indemnitee under the Prior Contribution Agreement shall not be terminated or impaired by any provision this Agreement, including, without limitation, MLP's or any MLP Indemnitee's right to be indemnified for HOLDINGS' breach of any representation, warranty, covenant or agreement under the Prior Contribution Agreement.

(c) Any claim for indemnity under this Agreement made by a Party Indemnitee shall be in writing, be delivered in good faith prior to the expiration of the respective survival period under Section 10.3(b) (to the extent applicable), and specify in reasonable detail the specific nature of the claim for indemnification hereunder ("Claim Notice"). Any such claim that is described in a timely (if applicable) delivered Claim Notice shall survive with respect to the specific matter described therein.

(d) Notwithstanding anything contained herein to the contrary, in no event shall HOLDINGS be obligated under this Agreement to indemnify (or be otherwise liable hereunder in any way whatsoever to) any of the MLP Indemnitees with respect to a breach of any representation or warranty, if MLP had Knowledge thereof at Closing and failed to notify HOLDINGS of such breach prior to Closing. Unless HOLDINGS or a Third Person shall have made a claim or demand or it appears reasonably likely that such a claim or demand appears reasonably likely, MLP shall not take any voluntary action that is intended by MLP to cause a Claim to be initiated that would be subject to indemnification by HOLDINGS.

(e) All Losses indemnified hereunder shall be determined net of any (i) Third Person Awards, (ii) Tax Benefits; and (iii) amount which specifically pertains to such Loss and is reflected in the calculations of the amounts set forth on the Final Settlement Statement.

10.4 Notice of Asserted Liability; Opportunity to Defend.

(a) All claims for indemnification hereunder shall be subject to the provisions of this Section 10.4. Any person claiming indemnification hereunder is referred to herein as the "Indemnified Party" or "Indemnitee" and any person against whom such claims are asserted hereunder is referred to herein as the "Indemnifying Party" or "Indemnitor."

(b) If any Claim is asserted against or any Loss is sought to be collected from an Indemnified Party, the Indemnified Party shall with reasonable promptness provide to the Indemnifying Party a Claim Notice. The failure to give any such Claim Notice shall not otherwise affect the rights of the Indemnified Party to indemnification hereunder unless the Indemnified Party has proceeded to contest, defend or settle such Claim or remedy such a Loss with respect to which it has failed to give a Claim Notice to the Indemnifying Party, but only to the extent the Indemnifying Party is prejudiced thereby. Additionally, to the extent the Indemnifying Party is prejudiced thereby, the failure to provide a Claim Notice to the Indemnifying Party shall relieve the Indemnifying Party from liability for such Claims and Losses that it may have to the Indemnified Party, but only to the extent the liability for such Claims or Losses is directly attributable to such failure to provide the Claim Notice.

(c) The Indemnifying Party shall have thirty (30) days from the personal delivery or receipt of the Claim Notice (the "Notice Period") to notify the Indemnified Party (i) whether or not it disputes the liability to the Indemnified Party hereunder with respect to the Claim or Loss, and in the event of a dispute, such dispute shall be resolved in the manner set forth in Section 11.8 hereof, (ii) in the case where Losses are asserted against or sought to be collected from an Indemnifying Party by the Indemnified Party, whether or not the Indemnifying Party shall at its own sole cost and expense remedy such Losses or (iii) in the case where Claims are asserted against or sought to be collected from an Indemnified Party, whether or not the Indemnifying Party shall at its own sole cost and expense defend the Indemnified Party against such Claim; provided however, that any Indemnified Party is hereby authorized prior to and during the Notice Period to file any motion, answer or other pleading that it shall deem necessary or appropriate to protect its interests or those of the Indemnifying Party (and of which it shall have given notice and opportunity to comment to the Indemnifying Party) and not prejudicial to the Indemnifying Party.

(d) If the Indemnifying Party does not give notice to the Indemnified Party of its election to contest and defend any such Claim described in Section 10.4(c)(iii) within the Notice Period, then the Indemnifying Party shall be bound by the result obtained with respect thereto by the Indemnified Party and shall be responsible for all costs incurred in connection therewith.

(e) If the Indemnifying Party is obligated to defend and indemnify the Indemnified Party, and the Parties have a conflict of interest with respect to any such Claim, then the Indemnified Party may, in its sole discretion, separately and independently contest and defend such Claim, and the Indemnifying Party shall be bound by the result obtained with respect thereto by the Indemnified Party and shall be responsible for all costs incurred in connection therewith.

(f) If the Indemnifying Party notifies the Indemnified Party within the Notice Period that it shall defend the Indemnified Party against a Claim, the Indemnifying Party shall have the right to defend all appropriate Proceedings, and with counsel of its own choosing (but reasonably satisfactory to the Indemnified Party) and such Proceedings shall be promptly settled (subject to obtaining a full and complete release of all

Indemnified Parties) or prosecuted by it to a final conclusion. If the Indemnified Party desires to participate in, but not control, any such defense or settlement it may do so at its sole cost and expense. If the Indemnified Party joins in any such Claim, the Indemnifying Party shall have full authority to determine all action to be taken with respect thereto, as long as such action could not create a liability to any of the Indemnified Parties, in which case, such action would require the prior written consent of any Indemnified Party so affected.

(g) If requested by the Indemnifying Party, the Indemnified Party agrees to cooperate with the Indemnifying Party and its counsel in contesting any Claim and in making any counterclaim against the Third Person asserting the Claim, or any cross-complaint against any person as long as such cooperation, counterclaim or cross-complaint could not create a liability to any of the Indemnified Parties.

(h) At any time after the commencement of defense by Indemnifying Party under Section 10.4(f) above of any Claim, the Indemnifying Party may request the Indemnified Party to agree in writing to the abandonment of such contest or to the payment or compromise by the Indemnifying Party of the asserted Claim, but only if the Indemnifying Party agrees in writing to be solely liable for such Claim; whereupon such action shall be taken unless the Indemnified Party determines that the contest should be continued and notifies the Indemnifying Party in writing within fifteen (15) days of such request from the Indemnifying Party. If the Indemnified Party determines that the contest should be continued, the amount for which the Indemnifying Party would otherwise be liable hereunder shall not exceed the amount which the Indemnifying Party had agreed to pay to compromise such Claim; provided that, the other Person to the contested Claim had agreed in writing to accept such amount in payment or compromise of the Claim as of the time the Indemnifying Party made its request therefor to the Indemnified Party, and further provided that, under such proposed compromise, the Indemnified Party would be fully and completely released from any further liability or obligation with respect to the matters which are the subject of such contested Claim.

10.5 Materiality Conditions. For purposes of determining whether an event described in this Article X has occurred for which indemnification under this Article X can be sought, any requirement in any representation, warranty, covenant or agreement by HOLDINGS or MLP, as applicable, contained in this Agreement that an event or fact be “material,” “Material,” meet a certain minimum dollar threshold or have a “Material Adverse Effect” or a material adverse effect (each a “Materiality Condition”) in order for such event or fact to constitute a misrepresentation or breach of such representation, warranty, covenant or agreement under this Agreement, such Materiality Condition shall be disregarded and such representations, warranties, covenants or agreements shall be construed solely for purposes of this Article X as if they did not contain such Materiality Conditions. Notwithstanding anything in this Section 10.5, any claim for indemnification under this Article X will be subject to Section 10.3.

10.6 Exclusive Remedy. AS BETWEEN THE MLP INDEMNITEES AND THE HOLDINGS INDEMNITEES, AFTER CLOSING (A) THE EXPRESS INDEMNIFICATION PROVISIONS SET FORTH IN THIS AGREEMENT, WILL BE THE SOLE AND EXCLUSIVE RIGHTS, OBLIGATIONS AND REMEDIES OF THE PARTIES WITH

RESPECT TO SAID AGREEMENT AND THE EVENTS GIVING RISE THERETO, AND THE TRANSACTIONS PROVIDED FOR THEREIN OR CONTEMPLATED THEREBY (OTHER THAN THE OTHER TRANSACTION DOCUMENTS) AND (B) NO PARTY HERETO NOR ANY OF ITS RESPECTIVE SUCCESSORS OR ASSIGNS SHALL HAVE ANY RIGHTS AGAINST ANY OTHER PARTY OR ITS AFFILIATES WITH RESPECT TO THE TRANSACTIONS PROVIDED FOR HEREIN OTHER THAN AS IS EXPRESSLY PROVIDED IN THIS AGREEMENT AND THE OTHER TRANSACTION DOCUMENTS.

10.7 Negligence and Strict Liability Waiver. WITHOUT LIMITING OR ENLARGING THE SCOPE OF THE INDEMNIFICATION OBLIGATIONS SET FORTH IN THIS AGREEMENT, AN INDEMNIFIED PARTY SHALL BE ENTITLED TO INDEMNIFICATION UNDER THIS AGREEMENT IN ACCORDANCE WITH THE TERMS HEREOF, REGARDLESS OF WHETHER THE LOSS OR CLAIM GIVING RISE TO SUCH INDEMNIFICATION OBLIGATION IS THE RESULT OF THE SOLE, CONCURRENT OR COMPARATIVE NEGLIGENCE, STRICT LIABILITY, OR VIOLATION OF ANY LAW OF OR BY SUCH INDEMNIFIED PARTY.

10.8 Limitation on Damages. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, IN NO EVENT SHALL ANY OF HOLDINGS, GP OR MLP BE LIABLE TO THE OTHER, OR TO THE OTHERS' INDEMNITEES, UNDER THIS AGREEMENT FOR ANY EXEMPLARY, PUNITIVE, REMOTE, SPECULATIVE, CONSEQUENTIAL, SPECIAL OR INCIDENTAL DAMAGES OR LOSS OF PROFITS; PROVIDED THAT, IF ANY OF THE HOLDINGS INDEMNITEES OR MLP INDEMNITEES IS HELD LIABLE TO A THIRD PERSON FOR ANY SUCH DAMAGES AND THE INDEMNITOR IS OBLIGATED TO INDEMNIFY SUCH HOLDINGS INDEMNITEES OR MLP INDEMNITEES FOR THE MATTER THAT GAVE RISE TO SUCH DAMAGES, THE INDEMNITOR SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE SUCH INDEMNITEES FOR SUCH DAMAGES.

10.9 Bold and/or Capitalized Letters. THE PARTIES AGREE THAT THE BOLD AND/OR CAPITALIZED LETTERS IN THIS AGREEMENT CONSTITUTE CONSPICUOUS LEGENDS.

ARTICLE XI
MISCELLANEOUS PROVISIONS

11.1 Expenses. Unless otherwise specifically provided for herein, each Party will bear its own costs and expenses (including legal fees and expenses) incurred in connection with the negotiation of this Agreement and the transactions contemplated hereby; provided that HOLDINGS will bear the cost of all Post-Closing Consents which must be obtained from any railroad.

11.2 Further Assurances. From time to time, and without further consideration, each Party will execute and deliver to the other Party such documents and take such actions as the other Party may reasonably request in order to more effectively implement and carry into effect the transactions contemplated by this Agreement.

11.3 Transfer Taxes. The Parties believe that the contribution of the Subject Interests as provided for herein is exempt from or is otherwise not subject to any and all sales, use, transfer, or similar Taxes. If any such sales, transfer, use or similar Taxes are due or should hereafter become due (including penalty and interest thereon) by reason of this transaction, MLP shall timely pay and solely bear all such type of Taxes.

11.4 Assignment. Neither Party may assign this Agreement or any of its rights or obligations arising hereunder without the prior written consent of the other Party; provided, however, MLP shall be permitted to assign this Agreement to an Affiliate prior to Closing, provided, that, notwithstanding such assignment, MLP shall continue to remain responsible for all obligations of MLP hereunder following such assignment.

11.5 Entire Agreement, No Amendment of Prior Transaction Agreement, Amendments and Waiver. This Agreement, together with the Transaction Documents and all certificates, documents, instruments and writings that are delivered pursuant hereto and thereto contain the entire understanding of the Parties with respect to the transactions contemplated hereby and supersede all prior agreements, arrangements and understandings relating to the subject matter hereof. Except as specified in Section 6.9, no term, provision or aspect of this Agreement or of any other Transaction Document shall have the effect of terminating, amending, extending, or enlarging or limiting the scope or intent, or of in any manner superseding the Prior Contribution Agreement or the transactions documents executed in connection therewith. This Agreement may be amended, superseded or canceled only by a written instrument duly executed by the Parties specifically stating that it amends, supersedes or cancels this Agreement. Any of the terms of this Agreement and any condition to a Party's obligations hereunder may be waived only in writing by that Party specifically stating that it waives a term or condition hereof. No waiver by either Party of any one or more conditions or defaults by the other in performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any future conditions or defaults, whether of a like or different character, nor shall the waiver constitute a continuing waiver unless otherwise expressly provided.

11.6 Severability. Each portion of this Agreement is intended to be severable. If any term or provision hereof is illegal or invalid for any reason whatsoever, such illegality or invalidity shall not affect the validity of the remainder of this Agreement.

11.7 Counterparts. This Agreement may be executed simultaneously in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

11.8 Governing Law, Dispute Resolution and Arbitration.

(a) Governing Law. This Agreement shall be governed by, enforced in accordance with, and interpreted under, the Laws of the State of Colorado, without reference to conflicts of Laws principles.

(b) Negotiation. In the event of any Arbitral Dispute, the Parties shall promptly seek to resolve any such Arbitral Dispute by negotiations between senior executives of the Parties who have authority to settle the Arbitral Dispute. When a Party believes there is an Arbitral Dispute under this Agreement that Party will give the other Party written notice of the Arbitral Dispute. Within thirty (30) days after receipt of such notice, the receiving Party shall submit to the other a written response. Both the notice and response shall include (i) a statement of each Party's position and a summary of the evidence and arguments supporting such position, and (ii) the name, title, fax number, and telephone number of the executive or executives who will represent that Party. If the Arbitral Dispute involves a claim arising out of the actions of any Person not a signatory to this Agreement, the receiving Party shall have such additional time as necessary, not to exceed an additional thirty (30) days, to investigate the Arbitral Dispute before submitting a written response. The executives shall meet at a mutually acceptable time and place within fifteen (15) days after the date of the response and thereafter as often as they reasonably deem necessary to exchange relevant information and to attempt to resolve the Arbitral Dispute. If one of the executives intends to be accompanied at a meeting by an attorney, the other executive shall be given at least five (5) Business Days' notice of such intention and may also be accompanied by an attorney.

(c) Failure to Resolve. If the Arbitral Dispute has not been resolved within sixty (60) days after the date of the response given pursuant to Section 11.8(b) above, or such additional time, if any, that the Parties mutually agree to in writing, or if the Party receiving such notice denies the applicability of the provisions of Section 11.8(b) or otherwise refuses to participate under the provisions of Section 11.8(b), either Party may initiate binding arbitration pursuant to the provisions of Section 11.8(d) below.

(d) Arbitration. Any Arbitral Disputes not settled pursuant to the foregoing provisions shall be resolved through the use of binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules"), as supplemented to the extent necessary to determine any procedural appeal questions by the Federal Arbitration Act (Title 9 of the United States Code) and in accordance with the following provisions:

(i) If there is any inconsistency between this Section 11.8(d) and the Arbitration Rules or the Federal Arbitration Act, the terms of this Section 11.8(d) will control the rights and obligations of the Parties.

(ii) Arbitration shall be initiated by a Party serving written notice, via certified mail, on the other Party that the first Party elects to refer the Arbitral Dispute to binding arbitration, along with the name of the arbitrator appointed by the Party demanding arbitration and a statement of the matter in controversy. Within thirty (30) days after receipt of such demand for arbitration, the receiving Party shall name its arbitrator. If the receiving Party fails or refuses to name its arbitrator within such thirty (30) day period, the second arbitrator shall be appointed, upon request of the Party demanding arbitration, by the Chief U.S. District Court Judge for the District of Colorado, or such other person designated by such judge. The two arbitrators so selected shall within thirty (30) days after their designation select a third arbitrator; provided, however, that if the two arbitrators are not able to agree on a third arbitrator within such thirty (30) day period, either Party may request the Chief U.S. District Court Judge for the

District of Colorado, or such other person designated by such judge to select the third arbitrator as soon as possible. If the Judge declines to appoint an arbitrator, appointment shall be made, upon application of either Party, pursuant to the Commercial Arbitration Rules of the American Arbitration Association. If any arbitrator refuses or fails to fulfill his or her duties hereunder, such arbitrator shall be replaced by the Party which selected such arbitrator (or if such arbitrator was selected by another Person, through the procedure which such arbitrator was selected) pursuant to the foregoing provisions.

(iii) The hearing will be conducted in Denver, Colorado, no later than sixty (60) days following the selection of the arbitrators or thirty (30) days after all prehearing discovery has been completed, whichever is later, at which the Parties shall present such evidence and witnesses as they may choose, with or without counsel. The Parties and the arbitrators should proceed diligently and in good faith in order that the award may be made as promptly as possible.

(iv) Except as provided in the Federal Arbitration Act, the decision of the arbitrators will be binding on and non-appealable by the Parties. Any such decision may be filed in any court of competent jurisdiction and may be enforced by any Party as a final judgment in such court.

(v) The arbitrators shall have no right or authority to grant or award exemplary, punitive, remote, speculative, consequential, special or incidental damages.

(vi) The Federal Rules of Civil Procedure, as modified or supplemented by the local rules of civil procedure for the U.S. District Court of Colorado, shall apply in the arbitration. The Parties shall make their witnesses available in a timely manner for discovery pursuant to such rules. If a Party fails to comply with this discovery agreement within the time established by the arbitrators, after resolving any discovery disputes, the arbitrators may take such failure to comply into consideration in reaching their decision. All discovery disputes shall be resolved by the arbitrators pursuant to the procedures set forth in the Federal Rules of Civil Procedure.

(vii) Adherence to formal rules of evidence shall not be required. The arbitrators shall consider any evidence and testimony that they determine to be relevant.

(viii) The Parties hereby request that the arbitrators render their decision within thirty (30) days following conclusion of the hearing.

(ix) The defenses of statute of limitations and laches shall be tolled from and after the date a Party gives the other Party written notice of an Arbitral Dispute as provided in Section 11.8(b) above until such time as the Arbitral Dispute has been resolved pursuant to Section 11.8(b), or an arbitration award has been entered pursuant to this Section 11.8(d).

(e) Recovery of Costs and Attorneys' Fees. If arbitration arising out of this Agreement is initiated by either Party, the decision of the arbitrators may include the award of court costs, fees and expenses of such arbitration (including reasonable attorneys' fees).

(f) Choice of Forum. If, despite the Parties' agreement to submit any Arbitral Disputes to binding arbitration, there are any court proceedings arising out of or relating to this Agreement or the transactions contemplated hereby, such proceedings shall be brought and tried in, and the Parties hereby consent to the jurisdiction of, the federal or state courts situated in the City and County of Denver, State of Colorado.

(g) Jury Waivers. THE PARTIES HEREBY WAIVE ANY AND ALL RIGHTS TO DEMAND A TRIAL BY JURY.

(h) Settlement Proceedings. All aspects of any settlement proceedings, including discovery, testimony and other evidence, negotiations and communications pursuant to this Section 11.8, briefs and the award shall be held confidential by each Party and the arbitrators, and shall be treated as compromise and settlement negotiations for the purposes of the Federal and State Rules of Evidence.

11.9 Notices and Addresses. Any notice, request, instruction, waiver or other communication to be given hereunder by either Party shall be in writing and shall be considered duly delivered if personally delivered, mailed by certified mail with the postage prepaid (return receipt requested), sent by messenger or overnight delivery service, or sent by facsimile to the addresses of the Parties as follows:

MLP:	DCP Midstream Partners, LP 370 — 17th Street, Suite 2775 Denver, Colorado 80202 Telephone: (303) 633-2900 Facsimile: (303) 633-2921 Attn: President
with a copy to:	DCP Midstream Partners, LP 370 — 17th Street, Suite 2775 Denver, Colorado 80202 Telephone: (303) 633-2900 Facsimile: (303) 633-2921 Attn: General Counsel
MIDSTREAM, GP or HOLDINGS:	DCP Midstream, LLC 370 — 17th Street, Suite 2500 Denver, Colorado 80202 Telephone: (303) 595-3331 Facsimile: (303) 605-2226 Attn: President

with a copy to: DCP Midstream, LLC
370 — 17th Street, Suite 2500
Denver, Colorado 80202
Telephone: (303) 605-1630
Facsimile: (303) 605-2226
Attn: General Counsel

or at such other address as either Party may designate by written notice to the other Party in the manner provided in this Section 11.9. Notice by mail shall be deemed to have been given and received on the third (3rd) day after posting. Notice by messenger, overnight delivery service, facsimile transmission (with answer-back confirmation) or personal delivery shall be deemed given on the date of actual delivery.

11.10 Press Releases. Except as may otherwise be required by securities Laws and public announcements or disclosures that are, in the reasonable opinion of the Party proposing to make the announcement or disclosure, legally required to be made, there shall be no press release or public communication concerning the transactions contemplated by this Agreement by either Party except with the prior written consent of the Party not originating such press release or communication, which consent shall not be unreasonably withheld or delayed. MLP, GP and HOLDINGS will consult in advance on the necessity for, and the timing and content of, any communications to be made to the public and, subject to legal constraints, to the form and content of any application or report to be made to any Governmental Authority that relates to the transactions contemplated by this Agreement.

11.11 Offset. Nothing contained herein or in any Transaction Document shall create a right of offset or setoff for any Party under this Agreement and each Party hereby waives and disclaims any such right of offset or setoff under all applicable Law (including common Law).

11.12 No Partnership; Third Party Beneficiaries. Nothing in this Agreement shall be deemed to create a joint venture, partnership, tax partnership, or agency relationship between the Parties. Nothing in this Agreement shall provide any benefit to any Third Person or entitle any Third Person to any claim, cause of action, remedy or right of any kind, it being the intent of the Parties that this Agreement shall not be construed as a third-party beneficiary contract; provided, however, that the indemnification provisions of Article X shall inure to the benefit of the MLP Indemnitees and the HOLDINGS Indemnitees as provided therein.

11.13 Negotiated Transaction. The provisions of this Agreement were negotiated by the Parties, and this Agreement shall be deemed to have been drafted by both Parties.

THE PARTIES HAVE signed this Agreement by their duly authorized officials as of the date first set forth above.

[Signatures begin on next page]

DCP LP HOLDINGS, LLC

By: /s/ D. Robert Sadler
Name: D. Robert Sadler
Title: Vice President, Strategic Planning

DCP MIDSTREAM, LLC

By: /s/ D. Robert Sadler
Name: D. Robert Sadler
Title: Vice President, Strategic Planning

DCP MIDSTREAM GP, LP

By: DCP MIDSTREAM GP, LLC,
Its General Partner

By: /s/ Donald A. Baldridge
Name: Donald A. Baldridge
Title: Vice President, Business Development

DCP MIDSTREAM PARTNERS, LP

By: DCP MIDSTREAM GP, LP,
Its General Partner

By: DCP MIDSTREAM GP, LLC,
Its General Partner

By: /s/ Donald A. Baldridge
Name: Donald A. Baldridge
Title: Vice President, Business Development

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)				
	2008	2007	2006	2005	2004
Earnings from continuing operations before fixed charges					
Pretax income (loss) from continuing operations before income or loss from equity method investments	$ 91.5	$ (55.0)	$ 32.7	$ 47.4	$ 30.2
Fixed charges	33.6	27.0	12.6	1.5	0.1
Amortization of capitalized interest	0.1	—	—	—	—
Distributed income of equity method investments	34.3	38.9	25.9	25.7	13.4
Less:					
Capitalized interest	(0.3)	(0.2)	(0.4)	—	—
Earnings from continuing operations before fixed charges	$ 159.2	$ 10.7	$ 70.8	$ 74.6	$ 43.7
Fixed charges					
Interest expense, net of capitalized interest	$ 32.6	$ 26.0	$ 11.4	$ 0.8	$ —
Capitalized interest	0.3	0.2	0.4	—	—
Estimate of interest within rental expense	0.5	0.6	0.7	0.7	0.1
Amortization of deferred loan costs	0.2	0.2	0.1	—	—
Total fixed charges	$ 33.6	$ 27.0	$ 12.6	$ 1.5	$ 0.1
Ratio of earnings to fixed charges	4.74	0.40	5.62	49.73	437.0

For purposes of determining the ratio of earnings to fixed charges, earnings are defined as pretax income or 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
Collbran Valley Gas Gathering, LLC	Colorado
DCP Antrim Gas, LLC	Michigan
DCP Assets Holding GP, LLC	Delaware
DCP Assets Holding, LP	Delaware
DCP Bay Area Pipeline, LLC	Michigan
DCP Black Lake Holding, LP	Delaware
DCP Collbran, LLC	Colorado
DCP Douglas, LLC	Colorado
DCP Grand Lacs, LLC	Michigan
DCP Intrastate Pipeline, LLC	Delaware
DCP Jackson, LLC	Michigan
DCP Lindsay, LLC	Delaware
DCP Litchfield, LLC	Michigan
DCP Michigan Pipeline & Processing, LLC	Michigan
DCP Midstream Partners Finance Corp.	Delaware
DCP Midstream Operating, LLC	Delaware
DCP Midstream Operating, LP	Delaware
Gas Supply Resources LLC	Texas
GSRI Transportation LLC	Texas
Jackson Pipeline Company	Michigan
Pelico Pipeline, LLC	Delaware
Wilbreeze Pipeline, LLC	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 4, 2009, 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) the wholesale propane logistics business and (b) DCP East Texas Holdings, LLC, 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, 2008.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 4, 2009

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 23, 2009, 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, 2008, filed with the Securities and Exchange Commission.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 27, 2009

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 4, 2009, relating to the consolidated financial statements and financial statement schedule of DCP East Texas Holdings, LLC as of December 31, 2008 and 2007 and for the three years in the period ended December 31, 2008 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the DCP East Texas Holdings, LLC consolidated financial statements through July 1, 2007 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, 2008.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 4, 2009

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 4, 2009, relating to the consolidated balance sheet of DCP Midstream GP, LP (a wholly owned subsidiary of DCP Midstream, LLC) as of December 31, 2008, appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 4, 2009

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 February 18, 2009, relating to the consolidated balance sheet of DCP Midstream, LLC as of December 31, 2008, appearing in this Annual Report on Form 10-K of DCP Midstream Partners, LP for the year ended December 31, 2008.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 4, 2009

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, 2008;

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 that 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 5, 2009

/s/ Mark A. Borer
Mark A. Borer
Chief Executive Officer
DCP Midstream GP, LLC

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Angela A. Minas 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, 2008;

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 that 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 5, 2009

/s/ Angela A. Minas
Angela A. Minas
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, 2008, 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 5, 2009

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, 2008, 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/ Angela A. Minas
Angela A. Minas
Chief Financial Officer
March 5, 2009

Exhibit 99.1

DCP Midstream GP, LP
(A Delaware Limited Partnership)

Consolidated Balance Sheet
As of December 31, 2008

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 and subsidiaries (the "Company") (a wholly owned subsidiary of DCP Midstream, LLC) as of December 31, 2008. 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 did not audit the financial statements of Discovery Producer Services, LLC ("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 $145,054,000 at December 31, 2008 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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audit and the report of the other auditors, such consolidated balance sheet presents fairly, in all material respects, the financial position of the Company as of December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 4, 2009

DCP MIDSTREAM GP, LP
CONSOLIDATED BALANCE SHEET

	December 31, 2008 (Millions)
ASSETS	
Current assets:	
Cash and cash equivalents	$ 48.0
Accounts receivable:	
Trade, net of allowance for doubtful accounts of $0.6 million	43.6
Affiliates	36.8
Inventories	20.9
Unrealized gains on derivative instruments	15.4
Other	0.5
Total current assets	165.2
Restricted investments	60.2
Property, plant and equipment, net	629.3
Goodwill	88.8
Intangible assets, net	47.7
Equity method investments	175.4
Unrealized gains on derivative instruments	8.6
Other long-term assets	4.8
Total assets	$ 1,180.0
LIABILITIES AND PARTNERS' DEFICIT	
Current liabilities:	
Accounts payable:	
Trade	$ 44.8
Affiliates	33.6
Unrealized losses on derivative instruments	17.7
Accrued interest payable	1.3
Other	27.4
Total current liabilities	124.8
Long-term debt	656.5
Unrealized losses on derivative instruments	26.0
Other long-term liabilities	14.3
Total liabilities	821.6
Non-controlling interests	363.7
Commitments and contingent liabilities	
Partners' deficit:	
Partners' equity	178.2
Note receivable from DCP Midstream, LLC	(183.0)
Accumulated other comprehensive loss	(0.5)
Total partners' deficit	(5.3)
Total liabilities and partners' deficit	$ 1,180.0

See accompanying notes to consolidated balance sheet.

DCP MIDSTREAM GP, LP
NOTES TO CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2008

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 approximately a 1% 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 Michigan system (acquired in October 2008); 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, 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 $3.8 million at December 31, 2008. Included in the consolidated balance sheet as accounts payable—trade were imbalances of $1.4 million at December 31, 2008.

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

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 customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit.

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 $5.4 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' sale of common units in June 2007, August 2007 and March 2008. As a result of our adoption of SFAS 160 on January 1, 2009, we will reclassify the deferred gain relating to this transaction from long-term liabilities to partners' equity in the consolidated balance sheet.

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 underlying 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, 2008, included in the consolidated balance sheet as other current liabilities amounted to $1.3 million and as other long-term liabilities amounted to $0.6 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. 162 "The Hierarchy of Generally Accepted Accounting Principles," **or SFAS 162** — In May 2008, the Financial Accounting Standards Board, or FASB, issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated financial position.

FASB Staff Position, or FSP, No. SFAS 142-3 "Determination of the Useful Life of Intangible Assets," **or FSP 142-3** — In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3, but do not expect a material impact on our consolidated financial position as a result of adoption.

SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133," **or SFAS 161** — In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our 2009 consolidated balance sheet.

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. SFAS 160 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 was effective for us on January 1, 2009, and did not have a significant impact on our consolidated financial position. As a result of adoption effective January 1, 2009, we will reclassify our non-controlling interests and the deferred gain relating to the sale of common units in DCP Partners from long term liabilities to partners' equity in the consolidated balance sheet.

***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 became 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;
- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and
- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not 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 recorded a transition adjustment of approximately $5.8 million as an increase to earnings and an insignificant amount as an increase to AOCI during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, 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 are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated financial position upon adoption.

***FSP No. 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,"* or FSP 157-3** — In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our financial position as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, "Amendment of FASB Interpretation No. 39,"* or FSP FIN 39-1** — In April 2007, the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheet.

EITF 08-06 "Equity Method Investment Accounting Considerations," or EITF 08-06 — In November 2008, the Emerging Issues Task Force issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee's issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for our Company effective January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

4. Acquisitions

Gathering and Compression Assets

On October 1, 2008, we acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. Under the terms of the acquisition, we paid a purchase price of $145.0 million, plus net working capital and other adjustments of $3.4 million, subject to additional customary purchase price adjustments. We may pay up to an additional $15.0 million to the sellers depending on the earnings of the assets after a three-year period. We financed the acquisition through utilization of our credit facility. In addition, we entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay up to $1.5 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied, and as a result, the amount was reduced to approximately $0.8 million per year as of December 31, 2008. We initially held a $25.0 million letter of credit to secure the seller's performance under this agreement and to secure the seller's indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $22.5 million as of December 31, 2008. The fees under the Omnibus Agreement increased $0.4 million per year effective October 1, 2008, in connection with the acquisition.

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $6.7 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained, which when finalized may result in material adjustments. The purchase price allocation is as follows:

	(Millions)
Cash	$ 1.7
Accounts receivable	2.1
Other assets	0.1
Other long term assets	3.8
Property, plant and equipment	116.1
Goodwill	6.7
Intangible assets	20.0
Other liabilities	(0.5)
Non-controlling interest in joint venture	(1.6)
Total purchase price allocation	$ 148.4

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. Under the Omnibus Agreement, DCP Midstream, LLC provided parental guarantees, totaling $43.0 million at December 31, 2008, to certain counterparties to our commodity derivative instruments.

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).

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

The Black Lake pipeline has experienced increased operating costs due to pipeline integrity testing that commenced in 2005 and was completed during the second quarter of 2008. Testing revealed irregularities, the more severe of which were repaired in October 2008 and the less severe of which are scheduled for repair in 2009. 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 repairing the Black Lake pipeline that are determined to be necessary as a result of the pipeline integrity testing. We anticipate repairs of approximately $0.8 million on the pipeline, which will be funded directly from Black Lake. We will not make contributions to Black Lake to cover these expenses.

In connection with our acquisition of our wholesale propane logistics business, DCP Midstream, LLC 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 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 Momentum Energy Group, Inc., or MEG, DCP Midstream, LLC 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.

We have not pursued indemnification under these agreements.

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 processed at our Minden and Ada plants, and sell condensate removed from the gas gathering systems that deliver to the Minden and Ada plants, and from our Pelico system to a subsidiary of DCP Midstream, LLC equal to that subsidiary's net weighted-average sales price, adjusted for transportation, processing 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 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 $3.8 million during 2008, to reimburse us for these capital projects.

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, 2008. 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.

Spectra Energy

We purchase a portion of our propane from and market propane on behalf of Spectra Energy. We anticipate continuing to purchase propane from and market propane on behalf of Spectra Energy in the ordinary course of business.

During the second quarter of 2008, we entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides us propane supply at our marine terminal, which is included in our Wholesale Propane Logistics segment, for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated for non-performance during the first quarter of 2008.

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 $1.9 million of capital reimbursements during the year ended December 31, 2008.

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

	December 31, 2008 (Millions)
DCP Midstream, LLC:	
Accounts receivable	$30.3
Accounts payable	$27.9
Spectra Energy:	
Accounts receivable	$ 4.0
Accounts payable	$ 5.3
ConocoPhillips:	
Accounts receivable	$ 2.5
Accounts payable	$ 0.4

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

	December 31, 2008 (Millions)
DCP Midstream, LLC:	
Unrealized losses—current	$(1.2)

6. Property, Plant and Equipment

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

	Depreciable Life	December 31, 2008 (Millions)
Gathering systems	15 — 30 Years	$ 405.0
Processing plants	25 — 30 Years	163.4
Terminals	25 — 30 Years	28.5
Transportation	25 — 30 Years	174.0
General plant	3 — 5 Years	6.0
Construction work in progress		43.5
Property, plant and equipment		820.4
Accumulated depreciation		(191.1)
Property, plant and equipment, net		$ 629.3

The above amounts include accrued capital expenditures of $12.3 million as of December 31, 2008, which are included in other current liabilities in the consolidated balance sheet.

We lease one of our Michigan transmission pipelines to a third party under a long-term contract. The carrying value of the pipeline is approximately $23.0 million, with accumulated depreciation of $0.2 million. Minimum future non-cancelable rental payments are as follows:

	Rental Payments (Millions)
2009	$ 3.0
2010	2.9
2011	2.9
2012	2.8
2013	2.3
Thereafter	20.7
Total	$ 34.6

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 $7.9 million at December 31, 2008.

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, 2008
		(Millions)
Beginning of period	$	80.2
Acquisitions		8.6
End of period	$	88.8

Goodwill increased during 2008 by $6.7 million as a result of the MPP acquisition, and by $1.9 million for the final purchase price allocation for the MEG subsidiaries acquired 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.

During the fourth quarter of 2008, as a result of the decline in the general equity market indices and in DCP Midstream Partners, LP's unit price on the New York Stock exchange, we updated our fair value analysis using current marketplace assumptions and concluded that the carrying value of goodwill is recoverable; therefore, we did not record any impairment charges during the year ended December 31, 2008. However, given the current volatility in the equity market, as well as volatile commodity prices, we will continue to monitor the recoverability of such amounts. Continued volatility and marketplace activity may alter our conclusion in the future, and could result in the recognition of an impairment charge.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related 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, 2008
		(Millions)
Gross carrying amount	$	52.5
Accumulated amortization		(4.8)
Intangible assets, net	$	47.7

Intangible assets increased in 2008 as a result of the MPP acquisition.

As of December 31, 2008, the remaining amortization periods range from approximately less than one year to 25 years, with a weighted-average remaining period of approximately 21 years.

8. Equity Method Investments

The following table summarizes our equity method investments:

	Percentage of Ownership as of December 31, 2008	Carrying Value as of December 31, 2008
		(Millions)
Discovery Producer Services LLC	40%	$ 105.0
DCP East Texas Holdings, LLC	25%	63.9
Black Lake Pipe Line Company	45%	6.3
Other	50%	0.2
Total equity method investments		$ 175.4

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 $39.7 million at December 31, 2008, 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 900-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 $6.0 million at December 31, 2008, which is associated with, and is being accreted over, the life of the underlying long-lived assets of Black Lake.

The following summarizes balance sheet information of our equity method investments:

	December 31, 2008 (Millions)
Balance sheet:	
Current assets	$ 104.3
Long-term assets	646.3
Current liabilities	(84.4)
Long-term liabilities	(22.4)
Net assets	$ 643.8

9. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 14 Risk Management Activities Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include over the counter, or OTC, instruments, such as natural gas, crude oil or NGL contracts.

Within our Natural Gas Services segment we typically use OTC derivative contracts in order to mitigate a portion of our exposure to natural gas, NGL and condensate price changes. These instruments are generally classified as Level 2. Depending upon market conditions and our strategy, we may enter into OTC derivative positions with a significant time horizon to maturity, and market prices for these OTC derivatives may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

Within our Wholesale Propane Logistics segment, we may enter into a variety of financial instruments to either secure sales or purchase prices, or capture a variety of market opportunities. Since financial instruments for NGLs tend to be counterparty and location specific, we primarily use the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and a market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected correlation of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar duration, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Short-Term and Restricted Investments

We are required to post collateral to secure the term loan portion of our credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated tax-exempt debt securities that have stated maturities of 20 years or more, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. Given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated tax-exempt debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2008, nearly all of our short-term and restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department's Temporary Guarantee Program for Money Market Funds.

The following table presents the financial instruments carried at fair value as of December 31, 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices In Active Markets (Level 1)	Internal Models With Significant Observable Market Inputs (Level 2)	Internal Models With Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
		(Millions)		
Current assets:				
Commodity derivative instruments (a)	$—	$ 15.1	$0.3	$ 15.4
Long-term assets:				
Restricted investments	$—	$ 60.2	$ —	$ 60.2
Commodity derivative instruments (b)	$—	$ 6.9	$1.7	$ 8.6
Interest rate instruments (b)	$—	$ —	$ —	$ —
Current liabilities (c):				
Commodity derivative instruments	$—	$ (1.2)	$ —	$ (1.2)
Interest rate instruments	$—	$(16.5)	$ —	$(16.5)
Long-term liabilities (d):				
Commodity derivative instruments	$—	$ (3.2)	$ —	$ (3.2)
Interest rate instruments	$—	$(22.8)	$ —	$(22.8)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheet.

(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheet.

(c) Included in current unrealized losses on derivative instruments in our consolidated balance sheet.

(d) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheet.

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our consolidated balance sheet for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers In/Out of Level 3” caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Balance at December 31, 2007	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/ Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Balance at December 31, 2008
			(Millions)		
Commodity derivative instruments:					
Current assets	$ 0.2	$ 0.8	$ —	$(0.7)	$0.3
Long-term assets	$ 1.5	$ 1.0	$(0.8)	$ —	$1.7
Current liabilities	$(1.6)	$(0.2)	$ —	$ 1.8	$ —
Long-term liabilities	$(0.2)	$ 0.2	$ —	$ —	$ —

(a) Amounts transferred in are reflected at fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

10. Estimated Fair Value of Financial Instruments

We have determined the 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 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.

11. Debt

Long-term debt was as follows:

	Principal Amount at December 31, 2008
	(Millions)
Revolving credit facility, weighed-average interest rate of 2.08%, due June 21, 2012 (a)	$ 596.5
Term loan facility, interest rate of 1.54%, due June 21, 2012	60.0
Total long-term debt (b)	$ 656.5

(a) $575.0 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.48% on the $596.5 million of outstanding debt under our revolving credit facility as of December 31, 2008.

(b) The term loan facility is fully secured by restricted investments.

Credit Agreement

We have an $824.6 million 5-year credit agreement that matures June 21, 2012, or the Credit Agreement, which consists of:

- a $764.6 million revolving credit facility; and
- a $60.0 million term loan facility.

At December 31, 2008, we had $0.3 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, 2008. As of December 31, 2008, the available capacity under the revolving credit facility was $171.5 million, which is net of approximately $21.7 million non-participation by Lehman Brothers Commercial Bank, or Lehman Brothers, as discussed below. We have incurred $0.6 million of debt issuance costs associated with the 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 Credit Agreement.

Under the 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 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 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 5.5 to 1.0. The 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 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.

Lehman Brothers is a lender in our Credit Agreement. Lehman Brothers has not funded its portion of our borrowing requests since its bankruptcy, and it is uncertain whether it will participate in future borrowing requests. Accordingly, the availability of new borrowings under the Credit Agreement has been reduced by approximately $25.4 million as of December 31, 2008. Our borrowing capacity may be further limited by the Credit Agreement’s financial covenant requirements. Except in the case of a default, amounts borrowed under our credit facility will not mature prior to the June 21, 2012 maturity date.

Other Agreements

As of December 31, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million, which reduces the amount of cash we may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under our credit facility.

12. 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; (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; and (4) the non-controlling interest holders’ portion of the net assets of Jackson Pipeline Company, a partnership we acquired with the MPP acquisition in October 2008.

We own approximately a 1% 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, 2008, DCP Partners had outstanding 24,661,754 common units and 3,571,429 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 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.

In March 2008, DCP Partners issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of $132.1 million, net of offering costs.

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 and 2008. Therefore, our 2% interest in these distributions was reduced to approximately 1%.

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. Currently, our distribution related to our incentive distribution rights is at the highest level. 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, or 3,571,428 units, converted into common units. DCP Partners determined that the criteria set forth in the partnership agreement for early termination of the subordination period occurred in February 2009 and, therefore, the remaining 3,571,429 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 approximately 1%, 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 2008:

Payment Date	Per Unit Distribution	Total Cash Distribution (Millions)
November 14, 2008	$0.600	$20.1
August 14, 2008	0.600	20.1
May 15, 2008	0.590	19.6
February 14, 2008	0.570	15.7

13. Partners' Deficit

At December 31, 2008, partners' deficit consisted of our capital account, AOCI and a note receivable from DCP Midstream, LLC.

As of December 31, 2008, we had a deficit balance of $5.3 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.

14. Risk Management Activities, Credit Risk and Financial Instruments

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

	December 31, 2008 (Millions)
Interest rate cash flow hedges:	
Net deferred losses in AOCI	$(0.5)

For the year ended December 31, 2008, 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, 2008, we had an outstanding letter of credit with a counterparty to our commodity derivative instruments of $10.0 million. This letter of credit reduces the amount of cash we may be required to post as collateral. As of December 31, 2008, we had no cash collateral posted with counterparties to our commodity derivative instruments.

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 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, 2008 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, 2008 is expected to be reclassified to earnings, through December 2011, as the underlying transactions impact earnings. Subsequent to July 1, 2007, the changes in fair value of financial derivatives are included in earnings. The agreements are with major financial institutions, which management expects to fully perform under the terms of the agreements.

As of December 31, 2008, we have mitigated the majority 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 commodities in future periods as well as select operating expense contracts.

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 $575.0 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, $0.2 million of the remaining net loss deferred in AOCI at December 31, 2008 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. $425.0 million of the agreements reprice prospectively approximately every 90 days and the remaining $150.0 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% 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.

15. 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.

All 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 200% 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, 2008, 21,705 units vested in January 2009, 15,101 units are expected to vest on December 31, 2009, and 8,544 units are expected to vest on December 31, 2010.

At December 31, 2008, there was approximately $0.3 million of unrecognized compensation expense related to the Performance Units that is expected to be recognized over a weighted-average period of 0.7 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 January 1, 2008	46,960	$32.93	
Granted	17,085	$33.85	
Forfeited	(12,025)	$32.42	
Outstanding at December 31, 2008	52,020	$33.35	$9.40
Expected to vest (a)	45,350	$31.70	$9.40

(a) Based on our December 31, 2008 estimated achievement of specified performance targets, the performance target for units granted in 2008 is 100%, for units granted in 2007 is 102%, and for units granted in 2006 is 140.4%. The estimated forfeiture rate for units granted in 2008 and 2007 is 50%, and for units granted in 2006 is 0%.

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. The remaining Phantom Units outstanding at December 31, 2008 vested 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 units, 4,000 units vested during 2007 and 500 units vested in February 2008.

In 2008, we granted 4,000 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 2008. All of these units vested during 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 Price per Unit
Outstanding at January 1, 2008	20,199	$24.56	
Granted	4,000	$35.88	
Forfeited	(4,000)	$24.05	
Vested	(6,501)	$32.91	
Outstanding at December 31, 2008	13,698	$24.05	$9.40
Expected to vest	13,698	$24.05	$9.40

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.

Restricted Phantom Units — Our General Partner's board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs outstanding at December 31, 2008 are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears.

At December 31, 2008, there was approximately $0.2 million of unrecognized compensation expense related to the RPUs that is expected to be recognized over a weighted-average period of 2.0 years. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2008	—	$ —	$ —
Granted	17,085	$33.85	
Forfeited	(2,395)	$35.88	
Vested	—	$ —	
Outstanding at December 31, 2008	14,690	$33.52	$9.40
Expected to vest	8,544	$33.85	$9.40

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate, which was estimated at 50% as of December 31, 2008. 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 certain awards issued under the LTIP in cash upon vesting. Compensation expense on these awards is recognized ratably over each vesting period, and will be remeasured each reporting period 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.

16. 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, 2008.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. During 2008 we acquired properties in Michigan. Michigan imposes a business tax of 0.8% on gross receipts, and 4.95% of Michigan taxable income. The sum of the gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final tax liability.

17. 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 — On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of our subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after we acquired the asset from DCP Midstream in December 2005. We intend to appeal this decision and will continue to defend ourselves vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated balance sheet for the year ended December 31, 2008.

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. 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) property insurance, which covers replacement value of all real and personal property and includes business interruption/ extra expense and (5) 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.

Minimum rental payments under our various operating leases in the year indicated are as follows at December 31, 2008:

	(Millions)
2009	$ 12.4
2010	9.0
2011	7.9
2012	7.0
2013	5.8
Thereafter	2.6
Total minimum rental payments	$ 44.7

18. 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) our Colorado and Wyoming systems, acquired in August 2007; and (5) our Michigan system, acquired in October 2008.

Wholesale Propane Logistics — The Wholesale Propane Logistics segment consists of six owned rail terminals, one of which idled in 2007 to consolidate our operations, 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.

The following table sets forth our segment information:

	December 31, 2008 (Millions)
Segment long-term assets:	
Natural Gas Services (a)	$ 856.4
Wholesale Propane Logistics	54.3
NGL Logistics	33.8
Other (b)	70.3
Total long-term assets	1,014.8
Current assets	165.2
Total assets	$ 1,180.0

(a) Long-term assets for our Natural Gas Services segment increased in 2008 as a result of our Michigan acquisition in October 2008.

(b) Other long-term assets not allocable to segments consist of restricted investments, unrealized gains on derivative instruments, and other long-term assets.

19. Subsequent Events

On February 27, 2009, a jury in the District Count, Harris County, Texas rendered a verdict in favor of El Paso E&P Company, L.P. and against one of DCP Partners' subsidiaries and DCP Midstream. As previously disclosed, the lawsuit, filed in December 2006, stems from an ongoing commercial dispute involving our Minden processing plant that dates back to August 2000, which includes periods of time prior to our ownership of this asset. Our responsibility for this judgment will be limited to the time period after DCP Partners acquired the asset from DCP Midstream in December 2005. DCP Partners intend to appeal this decision and will continue to defend vigorously against this claim. Nevertheless, as a result of the jury verdict we have reserved a contingent liability of $2.5 million for this matter, which is included in our consolidated balance sheet for the year ended December 31, 2008.

On February 25, 2009, DCP Partners entered into a Contribution Agreement with DCP Midstream, LLC, whereby DCP Midstream, LLC will contribute an additional 25.1% interest in East Texas to DCP Partners in exchange for 3.5 million Class D units, providing DCP Partners with a 50.1% interest in East Texas following the expected closing of the transaction in April 2009. This closing date is subject to extension for up to 45 days to allow for repairs or replacement to DCP Partners reasonable satisfaction any assets destroyed or damaged by certain casualty losses and time to enable the plant to process all available inlet volumes as defined in the Contribution Agreement. The Class D units will automatically convert into common units in August 2009 and will not be eligible to receive a distribution until the second quarter distribution payable in August 2009. DCP Midstream, LLC has agreed to provide a fixed-price NGL derivative by NGL component for the period of April 2009 to March 2010 for the acquired interest. Subsequent to this transaction, we will consolidate East Texas in our consolidated balance sheet.

On February 11, 2009, DCP Partners announced, along with DCP Midstream, LLC, that our East Texas natural gas processing complex and residue natural gas delivery system known as the Carthage Hub, have been temporarily shut in following a fire that was caused by a third party underground pipeline outside of our property line that ruptured. No employees or contractors were injured in the incident. There was no significant damage to the natural gas processing complex. As of February 25, 2009, the complex began processing through one of the five plants, and it is expected that full processing capacities will be restored for the entire complex over the next 30 days. Residue gas will be redelivered into limited available pipeline interconnects while the Carthage Hub undergoes inspection and repairs.

On February 17, 2009, the remaining 3,571,429 DCP Partners subordinated units were converted to common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners' partnership agreement.

In February 2009, DCP Partners entered into interest rate swap agreements to convert $275.0 million of the indebtedness on our revolving credit facility to a fixed rate obligation, thereby reducing the exposure to interest rate fluctuations. These interest rate swaps commence in December 2010 and expire in June 2012

On January 27, 2009, the board of directors of the General Partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

DCP Midstream, LLC
Consolidated Balance Sheet
As of December 31, 2008

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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, 2008. 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 provides a reasonable basis for our opinion.

In our opinion, such consolidated balance sheet presents fairly, in all material respects, the financial position of the Company as of December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 18, 2009

DCP MIDSTREAM, LLC
CONSOLIDATED BALANCE SHEET
(millions)

	December 31, 2008
ASSETS	
Current assets:	
Cash and cash equivalents	$ 133
Accounts receivable:	
Customers, net of allowance for doubtful accounts of $6 million	735
Affiliates	221
Other	44
Inventories	43
Unrealized gains on derivative instruments	419
Other	70
Total current assets	1,665
Property, plant and equipment, net	4,836
Restricted investments	60
Investments in unconsolidated affiliates	179
Intangible assets, net	319
Goodwill	565
Unrealized gains on derivative instruments	119
Other long-term assets	49
Total assets	$ 7,792
LIABILITIES AND MEMBERS' EQUITY	
Current liabilities:	
Accounts payable:	
Trade	$ 888
Affiliates	48
Other	46
Short-term borrowings	100
Unrealized losses on derivative instruments	398
Accrued interest payable	59
Accrued taxes	44
Other	188
Total current liabilities	1,771
Long-term debt	3,602
Unrealized losses on derivative instruments	81
Other long-term liabilities	376
Non-controlling interest	312
Commitments and contingent liabilities	
Members' equity:	
Members' interest	1,667
Accumulated other comprehensive loss	(17)
Total members' equity	1,650
Total liabilities and members' equity	$ 7,792

See Notes to Consolidated Balance Sheet

DCP MIDSTREAM, LLC
NOTES TO CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2008

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 gathering, processing, compressing, transporting and storing of natural gas, and fractionating, transporting, gathering, treating, processing and storing of natural gas liquids, or NGLs, as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. As of December 31, 2008, we owned an approximately 29% limited partnership interest, and an approximately 1% general partnership interest in DCP Partners, as well as incentive distribution rights that entitle us to receive an increasing share of available cash as 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.

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 financial statement 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 statement 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 include 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 or loss, or AOCI. No such gains or losses were deferred in AOCI at December 31, 2008. 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 derivatives associated with managing DCP Partners' commodity price risk. We have used the mark-to-market method of accounting for all commodity derivative instruments associated with managing DCP Partners commodity price risk since 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 underlying 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. The remaining non-trading derivatives (which are related to asset based activity) for which hedge accounting or the normal purchase or normal sale exception are not elected, are recorded at fair value on the balance sheet, under the following accounting methods:

Classification of Contract	Accounting Method
Trading Derivatives	Mark-to-market method [b]
Non-Trading Derivatives:	
Cash Flow Hedge [a]	Hedge method [c]
Fair Value Hedge	Hedge method [c]
Normal Purchase or Normal Sale	Accrual method [d]
Non-Trading Derivatives	Mark-to-market method [b]

[a] Effective July 1, 2007, all commodity cash flow hedges relating to derivatives associated with managing DCP Partners' commodity price risk are classified as non-trading derivative activity. Our other commodity cash flow hedges and 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 statements 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 statements 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 statements 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 statements 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. 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 statements 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 internally developed 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. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

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 customer contracts and related relationships, including commodity purchase, transportation and processing contracts. These intangible assets are amortized on a straight-line basis over the term of the contract or anticipated relationship, ranging from less than 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.

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 long-term assets.

Fair Value Measurements — We measure our derivative financial assets and liabilities related to our commodity trading activity and our interest rate swaps at fair value as of each balance sheet date. While we utilize as much information as is readily observable in the marketplace in determining fair value, to the extent that information is not available we may use a combination of indirectly observable facts or, in certain instances may develop our own expectation of the fair value. Calculating the fair value of an instrument is a highly subjective process and involves a significant level of judgment based on our interpretation of a variety of market conditions. The resulting fair value may be significantly different from one measurement date to the next. All unrealized gains and losses resulting from changes in the fair value of our interest rate swaps are recorded in the consolidated balance sheet within AOCI and long-term debt.

Distributions — Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or 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, 2008, we paid distributions of $721 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 periodic dividends 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, 2008, we paid dividends of $1,140 million to the members, allocated in accordance with their 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 consisted of both subordinated units and common units. The subordinated units were entitled to receive the minimum quarterly distribution only after DCP Partners' common unitholders received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. However, the subordination period ended, and the subordinated units were converted into common units, on a one for one basis, as certain distribution requirements, as defined in DCP Partners' partnership agreement, were met. The subordination period had an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert into common units on a one-for-one basis in February 2008 and permitted the other 50% of the subordinated units, or 3,571,429 units, to convert into common units on a one-for-one basis in February 2009, following the satisfactory completion of the tests for ending the subordination period contained in DCP Partners' partnership agreement. During the year ended December 31, 2008, DCP Partners paid distributions of approximately $45 million to its public unitholders. In addition to our partnership interests we hold incentive distribution rights, which entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved.

Equity-Based Compensation — Equity classified equity-based compensation cost is measured at fair value, based on the closing unit price at grant date, and is recognized as expense over the vesting period. Liability classified equity-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.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standard, or SFAS, No. 123(R) (Revised 2004) *"Share-Based Payment,"* or SFAS 123R, which establishes accounting for equity-based awards exchanged for employee and non-employee services. Accordingly, equity classified equity-based compensation cost is measured at grant date, based on the fair value of the award, and is recognized as expense over the requisite service period. Liability classified equity-based compensation cost is remeasured at each reporting date, and is recognized over the requisite service period.

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 $270 million of gain on sale of common units in DCP Partners as of December 31, 2008, which is included in other long-term liabilities in the consolidated balance sheet. As a result of our adoption of SFAS 160 on January 1, 2009, we will reclassify the deferred gain from long-term liabilities to members' equity in the consolidated balance sheet.

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* — *Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 162 "The Hierarchy of Generally Accepted Accounting Principles,"* or SFAS 162** — In May 2008, the FASB issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC's, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

FASB Staff Position, or FSP No. SFAS 142-3 "Determination of the Useful Life of Intangible Assets," **or FSP 142-3** — In April 2008, the FASB issued FSP 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

***SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*" or SFAS 161** — In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

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. SFAS 160 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 was effective for us on January 1, 2009 and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption, effective January 1, 2009 we will reclassify our non-controlling interest and deferred gain relating to the sale of common units in DCP Partners to members' equity.

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 became 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 was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;
- establishes a framework for measuring fair value;
- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;
- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of

profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and

- significantly expands the disclosure requirements around instruments measured at fair value.

Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not 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 recorded a transition adjustment of approximately $2 million as an increase to earnings during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, 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 are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial positions upon adoption.

***FSP, No. 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,"* or FSP 157-3** — In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, "Amendment of FASB Interpretation No. 39,"* or FSP FIN 39-1** — In April 2008 the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheet.

***EITF, 08-06 "Equity Method Investment Accounting Considerations,"* or EITF 08-06 —** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee's issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us effective January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets — On October 1, 2008, DCP Partners acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural gas transportation within Michigan. The results of MPP's operations have been included in the consolidated financial statements since that date. Under the terms of the acquisition, DCP Partners paid a purchase price of $145 million, plus net working capital and other adjustments of approximately $3 million, subject to additional customary purchase price adjustments. DCP Partners may pay up to an additional $15 million to the sellers depending on the earnings of the assets after a three-year period. DCP Partners financed the acquisition by liquidating a portion of its restricted investments. In addition, DCP Partners entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay DCP Partners up to approximately $2 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied and, as a result, the amount the seller will pay DCP Partners has been reduced to approximately $1 million per year as of December 31, 2008. DCP Partners initially held a $25 million letter of credit to secure the seller's contingent future performance under this agreement and to secure the seller's indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $23 million as of December 31, 2008.

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $6 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustments as additional information is obtained. When finalized, material adjustments may result. The purchase price allocation is as follows:

	(Millions)
Cash	$ 2
Accounts receivable	2
Property, plant and equipment	116
Goodwill	6
Intangible assets	20
Other long-term assets	4
Non-controlling interest	(2)
Total purchase price allocation	$ 148

In October 2008, we acquired certain pipeline and compressor station assets located in Kansas, Oklahoma and Texas from Northern Natural Gas for $49 million.

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 $138 million, including purchase price adjustments of $3 million during the first quarter of 2008. 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.

The purchase price allocation is as follows (in millions):

Cash	$ 42
Receivables	23
Other assets	2
Property, plant and equipment	282
Intangible assets	254
Goodwill	138
Payables	(18)
Other liabilities	(34)
Current debt	(20)
Non-controlling interest	(23)
Total purchase price allocation	$ 646

Dispositions

Disposition of Investments in Unconsolidated Affiliates — In October 2008, we sold certain interests in unconsolidated affiliates to unrelated third parties for $19 million in cash, subject to purchase price adjustments, and recognized a gain of $11 million.

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 joint venture in western Colorado, and assets in the Powder River Basin, including the Douglas gas gathering system in Wyoming. DCP Partners financed this transaction with $120 million of borrowings under the DCP Partners' Credit Agreement, the issuance of common units through a private placement with certain institutional investors 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. These units were registered with the SEC in January 2008. 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 operate these assets and they are 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 a 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 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. In December of 2008, we announced that we will contribute an additional 25% ownership interest in East Texas to DCP Partners in exchange for 100% DCP Partners' common units. This transaction is expected to close in April 2009.

3. Agreements and Transactions with Affiliates

ConocoPhillips

Long-term NGL Purchases Contract and Transactions — We sell a portion of our residue gas and NGLs to ConocoPhillips and its subsidiaries, including ChevronPhillips Chemical Company LLC, or CP Chem, a 50% equity investment of ConocoPhillips. In addition, we purchase 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.

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering, transportation and other 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 accounts receivable—affiliates as of December 31, 2008 are insurance recovery receivables of approximately $13 million.

During the second quarter of 2008, DCP Partners entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides DCP Partners propane supply at their marine terminal for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated during the first quarter of 2008.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase 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.

4. Inventories

Inventories were as follows:

	December 31, 2008 (millions)
Natural gas held for resale	$ 7
NGLs	36
Total inventories	$ 43

5. Property, Plant and Equipment

Property, plant and equipment by classification was as follows:

	Depreciable Life	December 31, 2008 (millions)
Gathering	15 - 30 years	$ 3,633
Processing	25 - 30 years	2,134
Transportation	25 - 30 years	1,329
Underground storage	20 - 50 years	141
General plant	3 - 5 years	219
Construction work in progress		367
		7,823
Accumulated depreciation		(2,987)
Property, plant and equipment, net		$ 4,836

Interest capitalized on construction projects in 2008 was approximately $10 million. At December 31, 2008, we had non-cancelable purchase obligations of approximately $83 million for capital projects anticipated to be completed in 2009.

DCP Partners leases one of the MPP transmission pipelines to a third party under a long-term contract. The carrying value of the pipeline is approximately $23 million, with accumulated depreciation of less than $1 million. Minimum future non-cancelable rental payments are as follows:

	(millions)
2009	$ 3
2010	3
2011	3
2012	3
2013	2
Thereafter	21
Total	$ 35

6. Goodwill and Intangible Assets

The changes in carrying amount of goodwill are as follows:

	December 31, 2008 (millions)
Goodwill, beginning of period	$ 556
Acquisitions	9
Goodwill, end of period	$ 565

Goodwill increased by $6 million during 2008 as a result of the amount that we recognized in connection with our acquisition of MPP, and by $3 million for the final purchase price allocation for the MEG acquisition.

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, 2008 indicated that our reporting units' fair values exceed their carrying or book values. Accordingly, no impairment of goodwill is indicated. During the fourth quarter of 2008, as a result of the decline in the unit price of DCP Partners' units on the New York Stock Exchange, we updated our fair value analysis of the DCP Partners' reporting unit using current marketplace assumptions and concluded that the carrying value of the goodwill associated with these units is recoverable. However, given the current volatility in the market, as well as volatile commodity prices, we will continue to monitor the recoverability of such amounts. Continued volatility and marketplace activity may alter our conclusion in the future, and could result in the recognition of an impairment charge.

Intangible assets consist primarily of customer contracts and related relationships, including commodity purchase, transportation and processing contracts. The gross carrying amount and accumulated amortization for intangible assets are as follows:

	December 31, 2008 (millions)
Gross carrying amount	$ 426
Accumulated amortization	(107)
Intangible assets, net	$ 319

Intangible assets increased by $20 million in 2008 as a result of the MPP acquisition. 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, 2008:

	Estimated Amortization (millions)
2009	$ 21
2010	21
2011	20
2012	20
2013	20
Thereafter	217
Total	$ 319

7. Investments in Unconsolidated Affiliates

We have investments in the following unconsolidated affiliates accounted for using the equity method:

	2008 Ownership	December 31, 2008 (millions)
Discovery Producer Services LLC	40.00%	$ 105
Main Pass Oil Gathering Company	66.67%	43
Mont Belvieu I	20.00%	11
Sycamore Gas System General Partnership	48.45%	10
Other unconsolidated affiliates	Various	10
Total investments in unconsolidated affiliates		$ 179

Discovery Producer Services LLC — Discovery operates a 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 280 miles of pipe, and several onshore laterals expanding their presence in the Gulf. The deficit between the carrying amount of the investment and the underlying equity of Discovery of $40 million at December 31, 2008, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Discovery.

Main Pass Oil Gathering Company — In December 2006, we acquired an additional 33.33% 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. We now own 66.67% of Main Pass with one other partner. 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 $11 million at December 31, 2008, 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 $9 million at December 31, 2008, 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 $6 million at December 31, 2008 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Sycamore.

The following summarizes combined balance sheet information of unconsolidated affiliates:

	December 31, 2008 (millions)
Balance sheet:	
Current assets	$ 86
Long-term assets	542
Current liabilities	(60)
Long-term liabilities	(26)
Net assets	$ 542

8. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money, and/or liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets, for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level; to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis, taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil, or natural gas futures) or over the counter instruments, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk exposure. To mitigate a portion of this risk, and to manage commodity price risk related primarily, to owned natural gas storage and pipeline assets we engage in natural gas asset based trading and marketing, we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which expose us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which may not be as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and a market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market, are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected correlation of NGL prices to crude oil, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt or our fixed rate debt for floating rate debt, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar characteristics, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified as Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Restricted Investments

We are required to post collateral to secure the term loan portion of DCP Partners' credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated debt securities that have stated maturities of 20 years or more, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. However, given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2008, nearly all of our restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department's Guarantee Program for Money Market Funds.

The following table presents the financial instruments carried at fair value as of December 31, 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices in Active Markets (Level 1)	Internal Models With Significant Observable Market Inputs (Level 2)	Internal Models With Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
	(millions)			
Current assets:				
Commodity derivative instruments (a)	$ 34	$ 175	$ 210	$ 419
Available-for-sale securities (b)	$ —	$ 15	$ —	$ 15
Long-term assets:				
Commodity derivative instruments (c)	$ 61	$ 36	$ 22	$ 119
Restricted investments	$ —	$ 60	$ —	$ 60
Current liabilities (d):				
Commodity derivative instruments	$(79)	$(145)	$(155)	$(379)
Interest rate instruments	$ —	$ (19)	$ —	$ (19)
Long-term liabilities (e):				
Commodity derivative instruments	$ (8)	$ (6)	$ (44)	$ (58)
Interest rate instruments	$ —	$ (23)	$ —	$ (23)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheet.

(b) Included in cash and cash equivalents in our consolidated balance sheet.

(c) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheet.

(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheet.

(e) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheet.

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our consolidated balance sheet for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers In/Out of Level 3” caption.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Balance at December 31, 2007	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Balance at December 31, 2008
Commodity derivative instruments:					
Current assets	$ 125	$ 143	$—	$(58)	$ 210
Long-term assets	$ 21	$ 2	$ (1)	$ —	$ 22
Current liabilities	$(112)	$(101)	$—	$ 58	$(155)
Long-term liabilities	$ (11)	$ (33)	$—	$ —	$ (44)

(a) Amounts transferred in are reflected at fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

9. 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.

The fair value of short-term investments, restricted investments, accounts receivable, accounts payable and short-term borrowings 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. The estimated fair value of long-term debt was $3,286 as of December 31, 2008.

10. 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, 2008 (millions)
Balance, beginning of period	$ 59
Accretion expense	5
Liabilities incurred	5
Liabilities settled	(1)
Balance, end of period	$ 68

11. Financing

Long-term debt was as follows:

	December 31, 2008 (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 November 2008, interest at 9.700% payable semiannually, due December 2013	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 (a)	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 Midstream's credit facility revolver, weighted-average interest rate of 2.69%, due April 2012	360
DCP Partners' credit facility revolver, weighted-average interest rate of 2.08%, due June 2012 (b)	596
DCP Partners' credit facility term loan, interest rate of 1.54%, due June 2012 (c)	60
Fair value adjustments related to interest rate swap fair value hedges (a)	43
Unamortized discount	(7)
Long-term debt	$ 3,602

(a) The swaps associated with this debt were terminated in December 2008. The remaining fair value adjustments of $43 million related to the swaps will be amortized as a reduction to interest expense through the maturity date of the debt.

(b) $575 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.48% on the $596 million of outstanding debt under the DCP Partners revolving credit facility as of December 31, 2008.

(c) The term loan facility is fully secured by restricted investments.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2008:

	Debt Maturities (millions)
2010	$ 800
2011	250
2012	1,016
2013	250
Thereafter	1,250
	3,566
Unamortized discount	(7)
Fair value adjustments related to interest rate swap fair value hedges	43
Long-term debt	$ 3,602

Debt Securities — In November 2008, we issued $250 million principal amount of 9.70% Senior Notes due 2013, or the 9.70% Notes, for proceeds of approximately $248 million, net of related offering costs. The 9.70% Notes mature and become due and payable on December 1, 2013. We will pay interest semiannually on June 1 and December 1 of each year, beginning June 1, 2009. We used $200 million of the proceeds of this offering to pay down our 364-day agreement that we entered into in April 2008 and the remainder was used for general corporate purposes.

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 pay interest semiannually on March 15 and September 15 of each year.

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.

DCP Midstream's 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. Any outstanding borrowings under the Facility at maturity may, at our option, be converted into an unsecured one-year term loan. The Facility may be used for letters of credit. As of December 31, 2008 there were borrowings of $360 million outstanding under the Facility and available capacity of $82 million. There was no commercial paper outstanding as of December 31, 2008. As of December 31, 2008, there were approximately $8 million in letters of credit outstanding. During 2008, total outstanding indebtedness under the Facility, including borrowings and drawn letters of credit issued under the Facility, was not less than $0 and did not exceed $360 million. The weighted average indebtedness outstanding under the Facility was $54 million for 2008.

Indebtedness under the Facility bears interest at a rate equal to, at our option and based on our current debt rating, either: (1) London Interbank Offered Rate, or 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.

In November 2008, we entered into a $350 million revolving credit facility agreement, or the $350 Million Facility, which matures in November 2009. The $350 Million Facility may be used to support our commercial paper program, for working capital requirements and for other general corporate purposes. As of December 31, 2008, there were no borrowings under the $350 Million Facility.

Indebtedness under the $350 Million Facility bears interest at a rate equal to, at our option and based on our debt rating at December 31, 2008, (1) the higher of (a) Citibank's prime rate per year, (b) the Federal Funds rate plus 0.5% per year, or (c) LIBOR plus 2.125% per year, with an increase of 0.25% per quarter, up to 3.125% or (2) LIBOR plus 2.125% per year, with an increase of 0.25% per quarter, up to 3.125%. The $350 Million Facility incurs an annual facility fee of 0.625% based on our current debt rating plus (a) 0.0% to 0.75%, escalating 0.25% quarterly, on the undrawn portions; and (b) 0.5% to 1.75 %, escalating quarterly, on the drawn portions.

In April 2008, we entered into a $300 million 364-day credit agreement, which was fully funded in April 2008, matures in April 2009 and is included within short-term borrowings in the consolidated balance sheet. The proceeds were used to partially fund the

April 2008 dividend to our parents and the debt bears interest at a rate equal to, at our option and based on our debt rating at December 31, 2008, either (1) LIBOR, plus 0.75% per year or (2) the higher of (a) the Federal Funds Rate in effect on such day plus 0.5% per year or (b) the JPMorgan Chase Bank prime rate per year. As of December 31, 2008 the outstanding balance under the 364-day agreement was $100 million and is classified in short-term borrowings in the accompanying consolidated balance sheet as of December 31, 2008.

The Facility, the $350 Million Facility and the 364-day credit agreement each require that we maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by these agreements) 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 qualifying asset acquisitions (as defined by the agreements) of not more than 5.5 to 1.0. Prior to being amended in April 2008, the Facility required that we maintain a debt to total capitalization ratio of less than or equal to 60%.

DCP Midstream Partners' Credit Facilities with Financial Institutions — On June 21, 2007, DCP Partners entered into the Amended and Restated Credit Agreement that matures on June 21, 2012, or the DCP Partners' Credit Agreement, which replaced the existing credit agreement, and consists of a total credit facility of $850 million, including a $790 million revolving credit facility and a $60 million term loan facility as of December 31, 2008. At December 31, 2008 DCP Partners had less than $1 million of letters of credit outstanding under the DCP Partners' Credit Agreement. As of December 31, 2008 the available capacity under the revolving credit facility was $172 million. The $172 million available capacity at December 31, 2008 is net of approximately $22 million non-participation by Lehman Brothers as discussed below. 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, 2008. During 2008, total outstanding indebtedness under the DCP Partners' Credit Agreement ranged from $630 million to $735 million. The weighted average total indebtedness outstanding under the DCP Partners' Credit Agreement was approximately $664 million for the year ended December 31, 2008.

Under the DCP Partners' 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%.

The DCP Partners' 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 the DCP Partners' 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 qualifying asset acquisitions in the midstream energy business of not more than 5.5 to 1.0. The DCP Partners' 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 the DCP Partners' Credit Agreement) of greater than or equal to 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.

Lehman Brothers Commercial Bank, or Lehman Brothers, is a lender under the DCP Partners' Credit Agreement. Lehman Brothers has not funded its portion of DCP Partners' borrowing requests since its bankruptcy, and it is uncertain whether it will participate in future borrowing requests. Accordingly, the availability of new borrowings under the DCP Partners' Credit Agreement has been reduced by approximately $22 million as of December 31, 2008. If Lehman Brothers elects not to participate in the DCP Partners' Credit Agreement, or does not transfer their commitment to another commercial lender under the credit facility, the availability will be reduced by up to an additional $3 million, for a total reduction of up to $25 million.

Other Agreements — As of December 31, 2008, DCP Partners had an outstanding letter of credit with a counterparty to their commodity derivative instruments of $10 million, which reduces the amount of cash DCP Partners may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners' Credit Agreement.

Other Financing — In March 2008, DCP Partners issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of approximately $132 million, net of offering costs.

12. Risk Management and Hedging 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, 2008
	(millions)
Interest rate derivative instruments:	
Losses reclassified from AOCI into earnings	$ 3
Commodity derivative activity:	
Unrealized gains from derivative activity	$ 194
Realized (losses) from derivative activity	(93)
Total trading and marketing gains, net	$ 101

For the year ended December 31, 2008, 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 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 various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides 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 language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and 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, 2008, we held cash deposits of $26 million included in other current liabilities and letters of credit of $163 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $42 million, included in other current assets, to secure our obligations to provide future services or to perform under financial contracts. As of December 31, 2008, DCP Partners had no cash collateral posted with counterparties to their commodity derivative instruments. As of December 31, 2008, DCP Partners had an outstanding letter of credit with a counterparty to its commodity derivative instruments of $10 million. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners' Credit Agreement. This letter of credit reduces the amount of cash DCP Partners may be required to post as collateral. 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 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.

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 natural gas and crude oil swaps and option contracts 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 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 derivatives associated with managing DCP Partners' commodity price risk. As a result, the remaining net loss deferred in AOCI at that time is being reclassified to sales of natural gas and petroleum products through December 2011, as the derivative transactions impact earnings. 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 statements of operations and comprehensive income. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

As of December 31, 2008, DCP Partners has mitigated a portion of their expected natural gas and condensate commodity price risk associated with the equity volumes from their gathering and processing operations through 2013 with natural gas, NGL and crude oil derivatives.

Commodity Cash Flow Hedges — During 2008, we executed a series of derivative financial instruments, which have been designated as cash flow hedges of the price risk associated with forecasted purchases of natural gas in 2010. For the year ended December 31, 2008, amounts recognized as comprehensive income in the consolidated statements of operations and comprehensive income for changes in the fair value of these hedge instruments were not significant. Amounts recognized for the effects of any ineffectiveness were also not significant. No amounts were reclassified to the consolidated statements of operations and comprehensive income as a result of settlements and no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the change in probability of forecasted transactions occurring. The deferred balance in AOCI was a loss of approximately $1 million at December 31, 2008. Amounts expected to be reclassified from AOCI into earnings during the next 12 months are not significant. Due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into 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) 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 commodities in future periods, as well as select operating expense contracts.

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 $575 million of the variable rate exposure to a fixed rate obligation. 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, 2008, $5 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. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% 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.

Prior to issuing fixed rate debt in August 2000, we entered into, and terminated, treasury locks and interest rate swaps to lock in the interest rate prior to it being fixed at the time of debt issuance. The losses realized on these agreements, which were terminated in 2000, are deferred in AOCI and amortized against interest expense over the life of the respective debt. The amount amortized to interest expense during the year ended December 31, 2008 was $1 million. The deferred balance was a loss of $4 million at December 31, 2008. Approximately $1 million of deferred net losses related to these instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the underlying hedged interest expense transaction occurs.

Interest Rate Fair Value Hedges — We entered into 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 were at a floating rate based on six-month LIBOR, which was re-priced semiannually through 2030. The swaps met conditions that permitted the assumption of no ineffectiveness. As such, for the life of the swaps no ineffectiveness was recognized. These swaps were terminated in December 2008 and we received cash of approximately $36 million net of a $7 million transaction fee. The remaining $43 million change in fair value of the underlying debt will be amortized as a reduction to interest expense through 2030.

13. 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 by DCP Partners in conjunction with the MEG acquisition in August 2007 and has a 30% non-controlling interest. Jackson Pipeline Company, LP was acquired by DCP Partners in conjunction with the MPP acquisition in October 2008 and has a 25% non-controlling interest. 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.

14. Equity-Based Compensation

We recorded equity-based compensation benefit as follows, the components of which are further described below:

	Year Ended December 31, 2008 (millions)
DCP Partners' Long-Term Incentive Plan (DCP Partners' Plan)	$ (1)
Duke Energy 1998 Plan and Spectra Energy Long-Term Incentive Plan	(1)
Total	$ (2)

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2008 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream's 2006 Plan:				
Relative Performance Units (RPUs)	8	$ —	72%(a)	5
Strategic Performance Units (SPUs)	3	$ 2	22%(a)	1
Phantom Units	5	$ 2	23%(a)	2
DCP Partners' Phantom Units	3	$ —	22%(a)	—
DCP Partners' Plan:				
Performance Units	3	$ —	50%	1
Phantom Units	0.5/3	$ —	0%	—
Restricted Phantom Units	3	$ —	50%	2
Duke Energy's 1998 Plan and Spectra Energy's 2007 LTIP Plan:				
Stock Options (no activity in 2007 or 2008)	0-10	$ —	NA	—
Stock Based Performance Awards	3	$ —	6%	—
Phantom Awards	1-5	$ —	6%	1
Other Stock Awards	1-5	$ —	NA	—

(a) Weighted-average estimated forfeiture rate

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 RPUs, Strategic Performance Units, or SPUs, 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, or DERs. 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 RPUs that will ultimately vest range from 0% to 200% of the outstanding RPUs, 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. The DERs 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, 2008	62,167	$43.41	
Forfeited	(5,850)	$43.36	
Vested or paid in cash	(3,047)	$42.86	
Outstanding at December 31, 2008	53,270	$43.44	$31.83
Expected to vest	26,892	$43.36	$32.06

Strategic Performance Units —The number of SPUs that will ultimately vest range from 0% to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period ending on December 31, 2008, 2009 and 2010, respectively, for units granted in 2006, 2007 and 2008. The final performance payout is determined by the compensation committee of our board of directors. The DERs 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, 2008	140,019	$43.49	
Granted	112,930	$35.49	
Forfeited	(14,617)	$41.86	
Vested or paid in cash	(3,047)	$42.86	
Outstanding at December 31, 2008	235,285	$39.76	$26.82
Expected to vest	166,879	$39.27	$26.46

The estimate of RPUs and SPUs 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 — The DERs 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, 2008	33,800	$43.57	
Granted	112,930	$35.49	
Forfeited	(5,270)	$39.15	
Outstanding at December 31, 2008	141,460	$37.39	$23.56
Expected to vest	115,334	$37.44	$23.80

DCP Partners' Phantom Units — The DERs 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 Price Per Unit
Outstanding at January 1, 2008	51,750	$34.33	
Forfeited	(2,750)	$51.10	
Outstanding at December 31, 2008	49,000	$33.39	$9.40
Expected to vest	48,750	$33.33	$9.40

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 and awards granted to employees in 2008 are accounted for as equity-based awards; all other awards are accounted for as liability awards.

Performance Units — The number of Performance Units that will ultimately vest range from 0% to 200% 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. 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 January 1, 2008	46,960	$32.93	
Granted	17,085	$33.85	
Forfeited	(12,025)	$32.42	
Outstanding at December 31, 2008	52,020	$33.35	$9.40
Expected to vest (a)	45,350	$31.70	$9.40

(a) Based on our December 31, 2008 estimated achievement of specified performance targets, the performance target for units that are expected to vest for units granted in 2008 is 100%, for units granted in 2007 is 102% and for units granted in 2006 is 150%. The estimated forfeiture rate for units granted in 2008 and 2007 is 50%, and for units granted in 2006 is 0%.

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. The remaining Phantom Units outstanding at December 31, 2008 vested 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 vested during 2008.

In 2008, DCP Partners granted 4,000 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of DCP Midstream as part of their annual director fees in 2008. All of these units vested during 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 Price Per Unit
Outstanding at January 1, 2008	20,199	$24.56	
Granted	4,000	$35.88	
Forfeited	(4,000)	$24.05	
Vested or paid in cash	(6,501)	$32.91	
Outstanding at December 31, 2008	13,698	$24.05	$9.40
Expected to vest	13,698	$24.05	$9.40

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.

Restricted Phantom Units — DCP Midstream Partners' General Partner's board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2008	—	$ —	$ —
Granted	17,085	$33.85	
Forfeited	(2,395)	$35.88	
Outstanding at December 31, 2008	14,690	$33.52	$9.40
Expected to vest	8,544	$33.85	$9.40

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate.

All awards issued under the 2006 Plan and the DCP Partners' Plan are intended to be settled in cash at each reporting period or units 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 January 1, 2008	1,815,956	$17.89	3.2	
Exercised	(151,480)	$13.45		
Forfeited	(106,889)	$19.77		
Outstanding at December 31, 2008	1,557,587	$18.19	2.4	$ 2
Exercisable at December 31, 2008	1,557,587	$18.19	2.4	$ 2

The total intrinsic value of options exercised during the year ended December 31, 2008 was approximately $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 January 1, 2008	937,248	$ 26.80	3.2	
Exercised	(68,869)	$ 18.91		
Forfeited	(72,400)	$ 28.06		
Outstanding at December 31, 2008	795,979	$ 27.36	2.4	$ 1
Exercisable at December 31, 2008	795,979	$ 27.36	2.4	$ 1

The total intrinsic value of options exercised during the year ended December 31, 2008 was approximately $1 million.

Stock-Based Performance Awards — There were no stock-based performance awards granted during the year ended December 31, 2008.

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 January 1, 2008	173,365	$15.58	
Vested	(83,762)	$15.39	
Forfeited	(59,663)	$15.39	
Outstanding at December 31, 2008	29,940	$16.50	$15.01
Expected to vest	28,200	$16.50	$15.01

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	86,683	$23.54	
Vested	(41,884)	$23.25	
Forfeited	(29,829)	$23.25	
Outstanding at December 31, 2008	14,970	$24.94	$15.74
Expected to vest	14,009	$24.94	$15.74

The total fair value of the performance stock awards that vested during the year ended December 31, 2008 was approximately $2 million. No awards were granted during the year ended December 31, 2008.

Phantom Stock Awards — There were no phantom stock awards granted during the year ended December 31, 2008.

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 January 1, 2008	77,210	$15.62	
Vested	(24,419)	$15.57	
Forfeited	(3,287)	$15.38	
Outstanding at December 31, 2008	49,504	$15.66	$15.01
Expected to vest	46,627	$15.66	$15.01

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	38,605	$23.60	
Vested	(12,209)	$23.53	
Forfeited	(1,644)	$23.24	
Outstanding at December 31, 2008	24,752	$23.66	$15.74
Expected to vest	23,163	$23.66	$15.74

The total fair value of the phantom stock awards that vested during the year ended December 31, 2008 was approximately $1 million. No awards were granted during the year ended December 31, 2008.

15. 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 contributed 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.

16. 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 (benefit) expense related to this corporation is included in our income tax (benefit) expense, along with state and local taxes of the limited liability company and other subsidiaries.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. During 2008, we acquired properties in Michigan, which imposes a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final income tax liability.

The Company has a net long-term deferred tax asset of approximately $3 million at December 31, 2008, which is included in other long-term assets on the consolidated balance sheet. The deferred tax asset is comprised of differences between the financial statement carrying amount and the tax basis of property, plant and equipment ($18 million liability), investments in consolidated affiliates ($10 million asset), and net operating loss ($11 million asset). The net operating losses begin expiring in 2021, which we expect to fully utilize.

17. 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 March 2008, after receiving regulatory approval, we finalized settlement of a lawsuit alleging migration of acid gas from a storage formation into a third-party producing formation. We obtained the land and the rights to the producing formation. This matter did not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

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, in 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.

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 results of operations, financial position or cash flows.

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 vehicles; (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.

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 storage, management, transportation 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 results of operations, financial position or cash flows.

On July 20, 2006, the State of New Mexico Environment Department issued Compliance Orders to us that listed air quality violations during the previous five years at three of our owned or operated facilities in New Mexico. The orders alleged a number of violations related to excess emissions beginning January 2001, and further required us to install flares for smokeless operations and to use the flares only for emergency purposes. On April 17, 2008, we signed a settlement agreement with the New Mexico Environment Department that resolved all alleged violations through the date of the settlement agreement. Under the terms of the settlement agreement, we paid approximately $2 million in civil penalties and agreed to fund $59 million in facility upgrades at three of our gas plants through April 2011.

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)
2009	$ 28
2010	25
2011	24
2012	22
2013	20
Thereafter	23
Total payments	$ 142

18. Guarantees and Indemnifications

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.

19. Subsequent Events

In February 2009, we announced that our East Texas natural gas processing complex and residue natural gas delivery system, known as the Carthage Hub, have been temporarily shut in following an explosion and fire that occurred when a nearby third party owned pipeline outside of our property line ruptured. We do not expect a material impact on our consolidated results of operations, cash flows or financial position as a result of this event.

In February 2009, the remaining 3,571,429 DCP Partners subordinated units were converted into common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners' partnership agreement.

On January 27, 2009, the board of directors of the DCP Partners' general partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.