DCP Midstream Partners, LP
Form 10-K
March 10, 2008

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

Form 10-K

(Mark One)

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

or

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

Commission file number: 001-32678

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

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

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 þ

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 þ 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 þ	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 þ

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

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

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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GLOSSARY OF TERMS

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

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

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

the amount of collateral we may be required to post from time to time in our transactions; and

general economic, market and business conditions.

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

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

Item 1. *Business*

Our Partnership

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

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

Our Natural Gas Services segment includes:

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

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the Ada processing plant and gathering system, which includes a 45 MMcf/d refrigeration natural gas processing plant supplied by approximately 130 miles of natural gas gathering pipelines, connected to approximately 210 receipt points, with throughput capacity of approximately 80 MMcf/d; and

the Pelico Pipeline, LLC system, or Pelico system, an approximately 600-mile intrastate natural gas gathering and transportation pipeline with throughput capacity of approximately 250 MMcf/d and connections to the Minden and Ada processing plants and approximately 450 other receipt points. The Pelico system delivers natural gas to multiple interstate and intrastate pipelines, as well as directly to industrial and utility end-use markets.

our Southern Oklahoma, or Lindsay, gathering system, that was acquired in May 2007, consists of approximately 225 miles of pipeline, with throughput capacity of approximately 35 MMcf/d;

our equity interests that were acquired in July 2007 from DCP Midstream, LLC, consist of the following:

our 40% interest in Discovery Producer Services LLC, or Discovery, which operates a 600 MMcf/d cryogenic natural gas processing plant, a natural gas liquids fractionator plant, an approximately 280-mile natural gas pipeline with approximate throughput capacity of 600 MMcf/d that transports gas from the Gulf of Mexico to its processing plant, and several onshore laterals expanding its presence in the Gulf; and

our 25% interest in DCP East Texas Holdings, LLC, or East Texas, which operates a 780 MMcf/d natural gas processing complex, a natural gas liquids fractionator and an 845-mile gathering system with approximate throughput capacity of 780 MMcf/d, as well as third party gathering systems, and delivers residue gas to interstate and intrastate pipelines; and

our Colorado and Wyoming gathering, processing and compression assets were acquired in August 2007 from DCP Midstream, LLC, and consist of the following:

our 70% operating interest in the approximately 30-mile Collbran Valley Gas Gathering system, or Collbran system, has assets in the Piceance Basin that gather and process natural gas from over 20,000 dedicated acres in western Colorado, and a processing facility with a capacity that is being expanded from an original capacity of 60 MMcf/d to 120 MMcf/d; and

The Powder River Basin assets, which include the approximately 1,320-mile Douglas gas gathering system, or Douglas system, with throughput capacity of approximately 60 MMcf/d and covers more than 4,000 square miles in northeastern Wyoming, and Millis terminal, and associated NGL pipelines in southwestern Wyoming.

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

six owned rail terminals located in the Midwest and northeastern United States, one of which is currently idle, with aggregate storage capacity of 25 MBbls;

one leased marine terminal located in Providence, Rhode Island, with storage capacity of 410 MBbls;

one pipeline terminal located in Midland, Pennsylvania with storage capacity of 56 MBbls; and

access to several open access pipeline terminals.

Our NGL Logistics segment includes:

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

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

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

Our Business Strategies

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

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

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

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

Our Competitive Strengths

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

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

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

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

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

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

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

Our Relationship with DCP Midstream, LLC and its Parents

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

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

Natural Gas and NGLs Overview

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

Natural Gas Demand and Production

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

Midstream Natural Gas Industry

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

Natural Gas Gathering

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

Natural Gas Compression

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

Natural Gas Processing and Transportation

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

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

Wholesale Propane Logistics Overview

General

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

Production of Propane

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

Transportation

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

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Storage

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

Delivery

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

Natural Gas Services Segment

General

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

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

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

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

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

Gathering Systems, Processing Plants and Transportation Systems

Following is operating data for our systems:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural Gas Markets

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

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

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

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

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

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

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

Customers and Contracts

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

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

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

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

Competition

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

Wholesale Propane Logistics Segment

General

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

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are

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generally able to provide our retail propane distribution customers with reliable, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We believe these factors generally allow us to maintain favorable relationships with our customers.

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

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

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

Our Terminals

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

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

Propane Supply

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

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

Customers and Contracts

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

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

Competition

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

NGL Logistics Segment

General

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

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

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NGL Pipelines

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

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

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

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

Customers and Contracts

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

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

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these processing plants to DCP Midstream, LLC. DCP Midstream, LLC has a sales agreement with Formosa. Additionally, DCP Midstream, LLC has a transportation agreement with TEPPCO Partners, L.P. that covers all of the NGL volumes transported on TEPPCO Partners, L.P. s South Dean NGL pipeline for delivery to the Seabreeze pipeline.

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

Safety and Maintenance Regulation

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

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

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

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to

prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

Regulation of Operations

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

Interstate Natural Gas Pipeline Regulation

The Discovery 105-mile mainline, approximately 60 miles of laterals and its market expansion project are subject to regulation by FERC, under the Natural Gas Act of 1938, or NGA. Natural gas companies may not charge rates that have been determined not to be just and reasonable. In addition, the FERC s authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- terms and conditions of services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

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

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change is just and reasonable as required by the NGA, the FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on

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its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

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

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

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

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

On July 19, 2007, FERC issued a proposed policy statement regarding the appropriate composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. FERC proposed to permit inclusion of publicly traded partnerships in the proxy group

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analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline s earnings and that evidence be provided in the form of a multiyear analysis of past earnings demonstrating a publicly traded partnership s ability to provide stable earnings over time. On November 15, 2007, the FERC requested additional comments regarding the method to be used for creating growth forecasts for publicly traded partnerships, and FERC held a technical conference on this issue in January 2008. The ultimate outcome of this proceeding is not certain and may result in new policies being established at FERC that would disallow the full use of distributions to unitholders by pipeline publicly traded partnerships in any proxy group comparisons used to determine return on equity in future rate proceedings.

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

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

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

On December 21, 2007, FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. Comments are due on March 13, 2008, and a technical conference will be held regarding these issues on April 3, 2008. Adoption of this proposal by FERC could result in additional administrative burdens and could result in increased capital costs.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and Congress, especially in light of potential market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005 (EPACT 2005), and the FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPACT 2005 prohibits the use of any manipulative or deceptive device or contrivance in connection with the purchase or sale of natural gas, electric energy or transportation subject to the FERC s jurisdiction. The FERC then adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are very vague and are subject to broad interpretation. Only two orders interpreting these rules have been issued to date, and each of these is subject to further proceedings. These orders reflect the FERC s view that it has broad latitude in determining whether specific behavior violates the rules. In addition, EPACT 2005 gave the FERC increased penalty authority for these violations. The FERC may now issue civil penalties of up to $1 million per day for each violation of FERC rules, and there are possible criminal penalties of up to $1 million and 5 years in prison. Given the FERC s broad mandate granted in EPACT 2005, it is assumed that if energy prices are high, or exhibit what the FERC deems to be unusual trading patterns, the FERC will investigate energy markets to determine if behavior unduly impacted or manipulated energy prices.

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

Intrastate Natural Gas Pipeline Regulation

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

Gathering Pipeline Regulation

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

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

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

Sales of Natural Gas

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

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

Propane Regulation

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

Interstate NGL Pipeline Regulation

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

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

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

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

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

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Intrastate NGL Pipeline Regulation

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

Environmental Matters

General

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

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

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

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

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

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

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion

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of the more significant environmental laws and regulations that relate to our business and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Air Emissions

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

Hazardous Substances and Waste

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

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

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

Water

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

Global Warming and Climate Change

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

Anti-Terrorism Measures

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

Employees

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

General

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

Item 1A. *Risk Factors*

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

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

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Risks Related to Our Business

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

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

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

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

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

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

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

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

These entities may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;

These entities may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and

These entities may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Service at our propane terminals may be interrupted.

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

We operate in a highly competitive business environment.

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

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

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

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

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

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

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

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

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

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

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

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

FERC also has the power to order refunds.

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

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

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

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

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

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

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

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

perform ongoing assessments of pipeline integrity;

identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

improve data collection, integration and analysis;

repair and remediate the pipeline as necessary; and

implement preventive and mitigating actions.

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

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

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

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

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

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

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

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

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

- mistaken assumptions about volumes, future contract terms with customers, revenues and costs, including synergies;
- an inability to successfully integrate the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;

change in competitive landscape;

unforeseen difficulties operating in new product areas or new geographic areas; and

customer or key employee losses at the acquired businesses.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Inherent in an Investment in Our Common Units

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

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

- neither our partnership agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC s directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;

- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, in resolving conflicts of interest;

- DCP Midstream, LLC and its affiliates, including Spectra Energy and ConocoPhillips, are not limited in their ability to compete with us. Please read DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us below;

- once certain requirements are met, our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the special committee of our general partner or our unitholders;

- some officers of DCP Midstream, LLC who provide services to us also will devote significant time to the business of DCP Midstream, LLC, and will be compensated by DCP Midstream, LLC for the services rendered to it;

our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;

our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;

our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;

our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

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

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

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

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

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

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

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

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

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

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

partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

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

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

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

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

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

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

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding units voting together as a single class is required to remove the general partner. As of December 31, 2007, our general partner and its affiliates owned approximately 34.4% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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

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

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

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

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

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

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

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

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

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

your proportionate ownership interest in us will decrease;

the amount of cash available for distribution on each unit may decrease;

because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;

the ratio of taxable income to distributions may increase;

the relative voting strength of each previously outstanding unit may be diminished; and

the market price of the common units may decline.

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

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

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

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

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

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

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

a court or government agency determined that we were conducting business in a state but had not complied with that particular state s partnership statute; or the right of holders of limited partner interests to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

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

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

Tax Risks to Common Unitholders

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

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

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

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

Item 3. *Legal Proceedings*

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

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

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

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

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

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PART II

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

Market Information

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

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

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

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

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Issuance of Unregistered Units

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

Distributions of Available Cash

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

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

less the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

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

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

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

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

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

Equity Compensation Plans

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

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

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

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

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

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

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

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

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

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

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

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(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.

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

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

Overview

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

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

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

Recent Events

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

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

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

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

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

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

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

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

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

Factors That Significantly Affect Our Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

General Trends and Outlook

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

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

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

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

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

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

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

Our Operations

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

Natural Gas Services Segment

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

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

from these arrangements would be reduced.

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

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

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

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

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

We sell natural gas to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies, marketing affiliates of DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties. In addition, under our merchant arrangements, we use a subsidiary of DCP Midstream, LLC as our agent to purchase natural gas from third parties at pipeline interconnect points, as well as residue gas from our Minden and Ada processing plants, and then resell the aggregated natural gas to third parties. We also have entered into a contractual arrangement with a subsidiary of DCP Midstream,

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LLC that requires DCP Midstream, LLC to supply Pelico s system requirements that exceed its on-system supply. Accordingly, DCP Midstream, LLC purchases natural gas and transports it to our Pelico system, where we buy the gas from DCP Midstream, LLC at the actual acquisition cost plus transportation service charges incurred. If our Pelico system has volumes in excess of the on-system demand, DCP Midstream, LLC will purchase the excess natural gas from us and transport it to sales points at an index based price less a contractually agreed to marketing fee. In addition, DCP Midstream, LLC may purchase other excess natural gas volumes at certain Pelico outlets for a price that equals the original Pelico purchase price from DCP Midstream, LLC plus a portion of the index differential between upstream sources to certain downstream indices with a maximum differential and a minimum differential plus a fixed fuel charge and other related adjustments. To the extent possible, we match the pricing of our supply portfolio to our sales portfolio in order to lock in value and reduce our overall commodity price risk. We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We occasionally will enter into financial derivatives to lock in price differentials across the Pelico system to maximize the value of pipeline capacity. These financial derivatives are accounted for using mark-to-market accounting. We also gather, process and transport natural gas under fee-based transportation contracts.

Wholesale Propane Logistics Segment

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

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

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

NGL Logistics Segment

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

How We Evaluate Our Operations

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

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

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

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

Our gross margin and segment gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin and segment gross margin in the same

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manner. The following table sets forth our reconciliation of gross margin to its most directly comparable financial measure calculated in accordance with GAAP:

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

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

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

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

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

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

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

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

The Omnibus Agreement also addresses the following matters:

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

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

DCP Midstream, LLC s obligation to continue to maintain its credit support, including without limitation guarantees and letters of credit, for our obligations related to commercial contracts with respect to its business or operations that were in effect at December 7, 2005 until the expiration of such contracts.

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

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

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

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

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

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

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

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

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

Critical Accounting Policies and Estimates

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

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

approximately $3.7 million.

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

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

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

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Results of Operations

Consolidated Overview

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

	Year Ended December 31, 2007	2006	2005	Variance 2007 vs. 2006 Increase (Decrease)	Percent	Variance 2006 vs. 2005 Increase (Decrease)	Percent
	(Millions, except as indicated)						
Operating revenues:							
Natural Gas Services(a)	$ 404.1	$ 415.3	$ 592.8	$ (11.2)	(2.7)%	$ (177.5)	(29.9)%
Wholesale Propane Logistics	459.6	375.2	359.8	84.4	22.5%	15.4	4.3%
NGL Logistics	9.6	5.3	191.7	4.3	81.1%	(186.4)	(97.2)%
Total operating revenues	873.3	795.8	1,144.3	77.5	9.7%	(348.5)	(30.5)%
Gross margin(b):							
Natural Gas Services	16.2	75.3	71.4	(59.1)	(78.4)%	3.9	5.5%
Wholesale Propane Logistics	25.5	16.0	21.8	9.5	59.4%	(5.8)	(26.6)%
NGL Logistics	4.9	4.1	3.8	0.8	19.5%	0.3	7.9%
Total gross margin	46.6	95.4	97.0	(48.8)	(51.2)%	(1.6)	(1.6)%
Operating and maintenance expense	(32.1)	(23.7)	(22.4)	8.4	35.4%	1.3	5.8%
General and administrative expense	(24.1)	(21.0)	(14.2)	3.1	14.8%	6.8	47.9%
Earnings from equity method investments(c)	39.3	29.2	25.7	10.1	34.6%	3.5	13.6%
Non-controlling interest in income	(0.5)			0.5	100.0%		
EBITDA(d)	29.2	79.9	86.1	(50.7)	(63.5)%	(6.2)	(7.2)%
Depreciation and amortization expense	(24.4)	(12.8)	(12.7)	11.6	90.6%	0.1	0.8%
Interest income	5.3	6.3	0.5	(1.0)	(15.9)%	5.8	*
Interest expense	(25.8)	(11.5)	(0.8)	14.3	*	10.7	*
Income tax expense	(0.1)		(3.3)	0.1	100.0%	(3.3)	(100.0)%
Net (loss) income	$ (15.8)	$ 61.9	$ 69.8	$ (77.7)	*	$ (7.9)	(11.3)%

Operating data:

Natural gas throughput (MMcf/d)(c)	756	666	629	90	13.5%	37	5.9%
NGL gross production (Bbls/d)(c)	22,122	19,485	17,562	2,637	13.5%	1,923	10.9%
Propane sales volume (Bbls/d)	22,798	21,259	22,604	1,539	7.2%	(1,345)	(6.0)%
NGL pipelines throughput (Bbls/d)(c)	28,961	25,040	20,565	3,921	15.7%	4,475	21.8%

* Percentage change is greater than 100%.

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

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

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

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

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

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

$88.1 million increase attributable to higher propane prices and higher sales volumes for our Wholesale Propane Logistics segment;

$66.2 million increase primarily attributable to an increase in natural gas, NGL and condensate sales volumes, including increases as a result of the MEG and Southern Oklahoma acquisitions, and increases in NGL and condensate prices, partially offset by a decrease in natural gas sales volumes, primarily as a result of an amendment to a contract with an affiliate in 2006, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation for our Natural Gas Services segment;

$7.3 million increase in transportation revenue primarily attributable to an increase in throughput volumes in our Natural Gas Services segment; and

$3.4 million increase due to changes in product mix and increased volumes for our NGL Logistics segment; offset by

$87.5 million decrease related to commodity derivative activity, an increase of $0.2 million of which is included in sales of natural gas, NGLs and condensate, and a decrease of $87.7 million of which is included in losses from derivative activity.

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

$59.1 million decrease for our Natural Gas Services segment primarily due to decreases related to commodity derivative activity, and a decrease in marketing margins from the decline in the differences of natural gas prices at various receipt and delivery points across our Pelico system, offset by an increase in NGL and condensate production, mainly as a result of the MEG and Southern Oklahoma acquisitions, an increase in natural gas throughput volumes and higher contractual fees charged to customers; offset by

$9.5 million increase for our Wholesale Propane Logistics segment due to higher per unit margins as a result of changes in contract mix and the ability to capture lower priced supply sources, decreased non-cash lower of cost or market inventory adjustments recognized in 2007, and higher sales volumes primarily due to the completion of the Midland terminal, which became operational in May 2007, partially offset by a decrease related to commodity derivative activity; and

$0.8 million increase for our NGL Logistics segment primarily attributable to changes in product mix and increased volumes, as well as increased transportation revenue.

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

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

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

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

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

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

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

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

$190.3 million decrease primarily attributable to lower sales for our Seabreeze pipeline, primarily due to a change in contract terms in December 2005, between DCP Midstream, LLC and us, from a purchase and sale arrangement to a fee-based contractual transportation arrangement for our NGL Logistics segment; and

$181.3 million decrease attributable primarily to lower natural gas prices and sales volumes, and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation, partially offset by an increase in NGL and condensate prices and sales volumes for our Natural Gas Services segment; offset by

$15.2 million increase attributable to higher propane prices, which were offset by lower sales volumes for our Wholesale Propane Logistics segment;

$4.7 million increase in transportation revenue primarily attributable to an increase in volumes and a change in contract terms in December 2005 for our Seabreeze pipeline, from a purchase and sale arrangement to a fee-based contractual transportation arrangement; and

$3.2 million increase related to commodity derivative activity.

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

$5.8 million decrease due to non-cash lower of cost or market inventory adjustments, decreased sales volumes, and increased product and transportation costs for our Wholesale Propane Logistics segment; offset by

$3.9 million increase for our Natural Gas Services segment primarily due to higher NGL and condensate prices, and an increase in natural gas throughput volumes, offset by lower natural gas prices, decreases due to a change in contract mix, and decreased marketing activity and throughput across the Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system, which impacted gross margin more significantly in 2005 than in 2006. The market conditions causing the differentials in natural gas prices at various receipt and delivery points may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

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

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

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

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

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

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

Results of Operations Natural Gas Services Segment

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

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

* Percentage change is greater than 100%.

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

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

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

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

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

$83.3 million decrease related to commodity derivative activity, an increase of $0.2 million of which is included in sales of natural gas, NGLs and condensate, and a decrease of $83.5 million of which is included in losses from derivative activity; offset by

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

$17.2 million increase attributable to increased NGL and condensate prices; and

$5.9 million increase in transportation and processing services revenue primarily attributable to an increase in natural gas throughput.

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

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

$83.3 million decrease related to commodity derivative activity;

$2.5 million decrease attributable primarily to a decrease in marketing margins from the decline in the differences in natural gas prices at various receipt and delivery points across our Pelico system, which were atypically high in 2006; partially offset by

$25.2 million increase primarily attributable to an increase in NGL and condensate production, partially as a result of the MEG and Southern Oklahoma acquisitions, and an increase in natural gas throughput volumes;

$1.0 million increase primarily attributable to higher contractual fees charged to customers; and

$0.5 million increase primarily attributable to favorable frac spreads.

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

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

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

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

Increased equity earnings from Discovery were the result of an increase in Discovery s net income of $18.0 million, or 60%, due primarily to $39.0 million higher gross processing margins resulting from higher NGL sales volumes and NGL prices, partially offset by $9.9 million lower fee-based transportation, gathering, processing and fractionation revenues, $5.9 million higher operating and maintenance expense and $2.2 million higher other expenses. In addition, exceptionally strong commodity margins compelled Discovery s customers to process their natural gas rather than by-pass, which led to higher product sales revenues on Discovery s percent-of-proceeds and keep-whole processing contracts.

Increased equity earnings from East Texas were the result of an increase in East Texas s net income of $10.7 million, or 22%, due primarily to a $28.5 million increase as a result of higher commodity prices and a $1.1 million decrease in income tax expense due to recording a deferred tax liability of $1.8 million in 2006 related to the Texas margin tax; partially offset by an $11.6 million decrease due to a decline in natural gas volumes, a $3.0 million decrease due to decreased fee-based revenue, and an increase in operating and maintenance expenses of $2.8 million, primarily due to increased contract services, materials and supplies, and labor an benefits, increased depreciation expense of $1.2 million due to the addition of a new pipeline, and increased general and administrative expenses of $0.6 million, primarily due to higher allocated costs from DCP Midstream, LLC.

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

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

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

$114.1 million decrease attributable to a decrease in natural gas sales volumes and an amendment to a contract with an affiliate, which resulted in a prospective change in the reporting of certain Pelico revenues from a gross presentation to a net presentation; and

$87.3 million decrease attributable to a decrease in natural gas prices; offset by

$10.1 million increase primarily attributable to higher NGL and condensate sales volumes;

$10.0 million increase attributable to an increase in NGL and condensate prices;

$2.9 million increase related to commodity derivative activity; and

$0.9 million increase in transportation revenue primarily attributable to an increase in natural gas throughput.

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

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

$6.2 million increase attributable to higher NGL and condensate prices and favorable frac spreads, partially offset by lower natural gas prices. The frac spreads that existed during 2006 were higher than in recent years and may not continue in the future;

$5.2 million increase primarily attributable to an increase in natural gas throughput volumes;

$2.9 million increase related to commodity derivative activity; and

$0.5 million increase attributable to higher contractual fees charged to customers related to pipeline imbalances; offset by

$5.1 million decrease primarily attributable to a change in contract mix;

$4.0 million decrease attributable to a decrease in marketing activity and throughput across our Pelico system due to atypical differences in natural gas prices at various receipt and delivery points across the system. The market conditions causing the differentials in natural gas prices may not continue in the future, nor can we assure our ability to capture upside margin if these market conditions do occur; and

$1.8 million decrease attributable to higher netback prices paid to the producers at Minden and Ada.

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

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

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

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

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

Results of Operations Wholesale Propane Logistics Segment

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

	Year Ended December 31,			Variance 2007 vs. 2006		Variance 2006 vs. 2005	
	2007	2006	2005	Amount	Percent	Amount	Percent
	(Millions, except operating data)						
Operating revenues:							
Sales of propane	$ 463.1	$ 375.0	$ 359.8	$ 88.1	23.5%	$ 15.2	4.2%
Transportation and processing services	0.6	0.1	0.2	0.5	*	(0.1)	(50.0)%
(Losses) gains from derivative activity	(4.1)	0.1	(0.2)	(4.2)	*	0.3	*
Total operating revenues	459.6	375.2	359.8	84.4	22.5%	15.4	4.3%
Purchases of propane	434.1	359.2	338.0	74.9	20.9%	21.2	6.3%

Segment gross margin(a)		25.5		16.0		21.8		9.5	59.4%		(5.8)	(26.6)%
Operating and maintenance expense		(10.4)		(8.6)		(8.2)		1.8	20.9%		0.4	4.9
Depreciation and amortization expense		(1.1)		(0.8)		(1.0)		0.3	37.5%		(0.2)	(20.0)%
Segment net income	$	14.0	$	6.6	$	12.6	$	7.4	*	$	(6.0)	(47.6)%
Operating Data:												
Propane sales volume (Bbls/d)		22,798		21,259		22,604		1,539	7.2%		(1,345)	(6.0)%

* Percentage change is greater than 100%.

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

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

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

$60.8 million increase attributable to higher propane prices;

$27.3 million increase attributable to higher propane sales volumes as a result of colder weather in the northeastern United States and the completion of the Midland terminal, which became operational in May 2007; and

$0.5 million increase in transportation and processing services; offset by

$4.2 million decrease related to commodity derivative activity.

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

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

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

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

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

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

$36.6 million increase attributable to higher propane prices; and

$0.3 million increase related to commodity derivative activity; offset by

$21.4 million decrease attributable to lower propane sales volumes; and

$0.1 million decrease in transportation revenues.

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

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

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

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

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Results of Operations NGL Logistics Segment

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

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

* Percentage change is greater than 100%.

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

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

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

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

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

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

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

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

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

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

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

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

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

$3.9 million increase in transportation revenue attributable to an increase in volumes and a change in contract terms in December 2005, from a purchase and sale arrangement to a fee-based contractual transportation arrangement.

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

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

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

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

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

Liquidity and Capital Resources

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

We expect our sources of liquidity to include:

cash generated from operations;

cash distributions from our equity method investments;

borrowings under our revolving credit facility;

- cash realized from the liquidation of securities that are pledged under our term loan facility;
- issuance of additional partnership units; and
- debt offerings.

We anticipate our more significant uses of resources to include:

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

collateral with counterparties to our swap contracts to secure potential exposure under these contracts; and

quarterly distributions to our unitholders.

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

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

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

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

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

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default of a material agreement or payment obligation, that are reasonably likely to have a material adverse effect on the business, operations or financial condition of East Texas.

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

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

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

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

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

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

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

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

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

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

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

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

During 2007, we had the following borrowings:

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

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

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

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

maintenance capital expenditures, which are cash expenditures where we add on to or improve capital assets owned or acquire or construct new capital assets if such expenditures are made to maintain, including over the long term, our operating capacity or revenues; and

expansion capital expenditures, which are cash expenditures for acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets) in each case if such addition, improvement, acquisition or construction is made to increase our operating capacity or revenues.

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

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

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

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

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

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

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

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

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

Bridge Loan

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

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

Total Contractual Cash Obligations and Off-Balance Sheet Obligations

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

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

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

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

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

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

Recent Accounting Pronouncements

***Statement of Financial Accounting Standards, or SFAS, No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51*, or SFAS 160** In December 2007, the Financial Accounting Standards Board, or FASB, issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009.

Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

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

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

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

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

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

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

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

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

Risk Management Policy

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

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

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

Credit Risk

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

Interest Rate Risk

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

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

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

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Commodity Price Risk

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

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

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

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

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

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

Period		**Commodity**	**Notional Volume**	**Reference Price**	**Swap Price Range**
January 2008	December 2008	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2009	December 2009	Natural Gas	4,000 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2010	December 2010	Natural Gas	3,900 MMBtu/d	Texas Gas Transmission Price(a)	$9.20/MMBtu
January 2008	December 2013	Natural Gas	1,500 MMBtu/d	NYMEX Final Settlement Price(b)	$8.22/MMBtu
January 2008	December 2013	Natural Gas Basis	1,500 MMBtu/d	IFERC Monthly Index Price for Panhandle Eastern Pipe Line(c)	NYMEX less $0.68/MMBtu
January 2008	June 2008	Natural Gas	3,320 MMBtu/d	IFERC Monthly Index Price for Colorado Interstate Gas(d)	$6.85/MMBtu

January 2008	June 2008	Natural Gas Liquids	14,310 gallons per day	Conway In-Line and Mt. Belvieu Non-TET(e)	$0.97/gallon
January 2008	December 2008	Crude Oil	2,300 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2009	December 2009	Crude Oil	2,225 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2010	December 2010	Crude Oil	2,190 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$63.05 - $67.60/Bbl
January 2011	December 2011	Crude Oil	2,125 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$66.72 - $71.35/Bbl
January 2012	December 2012	Crude Oil	2,100 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$66.72 - $71.00/Bbl
January 2013	December 2013	Crude Oil	1,250 Bbls/d	Asian-pricing of NYMEX crude oil futures(f)	$67.60 - $71.20/Bbl

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

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

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

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

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

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

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

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

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

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

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

	Per Unit Decrease	Unit of Measurement	Estimated Decrease in Annual Net Income (Millions)
Natural gas prices	$ 1.00	MMBtu	$ 1.2

NGL prices	$	0.10	Gallon	$	2.8
Crude oil prices	$	5.00	Barrel	$	0.3

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

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

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

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

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

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

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

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

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

	Fair Value of Contracts as of December 31, 2007					
Sources of Fair Value	**Maturity in 2008**	**Maturity in 2009**	**Maturity in 2010**	**Maturity in 2011**	**Maturity in 2012 and Thereafter**	**Total Fair Value**
			(Millions)			
Prices supported by quoted market prices and other external sources	$ (26.1)	$ (22.2)	$ (17.4)	$ (12.7)	$ (16.7)	$ (95.1)

Prices based on models or other valuation techniques	(1.7)	1.1	0.9	0.1	(0.4)	
Total	$ (27.8)	$ (21.1)	$ (16.5)	$ (12.6)	$ (17.1)	$ (95.1)

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

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

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

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM PARTNERS, LP CONSOLIDATED FINANCIAL STATEMENTS:

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

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

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

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

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

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

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24.5	$ 46.2
Short-term investments	1.3	0.6
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1.2 million and $0.3 million, respectively	81.7	43.4
Affiliates	52.1	34.8
Inventories	37.3	30.1
Unrealized gains on derivative instruments	3.1	4.2
Other	18.5	0.3
Total current assets	218.5	159.6
Restricted investments	100.5	102.0
Property, plant and equipment, net	500.7	194.7
Goodwill	80.2	29.3
Intangible assets, net	29.7	2.8
Equity method investments	187.2	170.2
Unrealized gains on derivative instruments	2.7	6.5
Other long-term assets	1.2	0.8
Total assets	$ 1,120.7	$ 665.9
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 110.2	$ 66.9
Affiliates	55.6	50.4
Unrealized losses on derivative instruments	30.9	0.7
Accrued interest payable	1.6	1.1
Other	21.3	7.4
Total current liabilities	219.6	126.5
Long-term debt	630.0	268.0
Unrealized losses on derivative instruments	70.0	2.7
Other long-term liabilities	5.8	1.0
Total liabilities	925.4	398.2

Non-controlling interests	26.9	
Commitments and contingent liabilities		
Partners equity:		
Predecessor equity		164.3
Common unitholders (16,840,326 and 10,357,143 units issued and outstanding, respectively)	308.8	223.4
Class C unitholders (0 and 200,312 units issued and outstanding, respectively)		(20.7)
Subordinated unitholders (7,142,857 convertible units issued and outstanding at both periods)	(120.1)	(101.6)
General partner interest	(5.4)	(5.0)
Accumulated other comprehensive (loss) income	(14.9)	7.3
Total partners equity	168.4	267.7
Total liabilities and partners equity	$ 1,120.7	$ 665.9

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF OPERATIONS

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

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

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

See accompanying notes to consolidated financial statements.

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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 (Loss) Income	Total Partners Equity
				(Millions)			
Balance, January 1, 2005	$ 400.5	$	$	$	$	$	$ 400.5
Net change in parent advances	(137.7)						(137.7)
Proceeds from initial public offering of 10,350,000 common units		222.5					222.5
Underwriters discount and offering expenses		(9.3)		(6.4)	(0.4)		(16.1)
Distribution to unitholders	(218.7)						(218.7)
Allocation of predecessor equity in exchange for 7,143 common units, 7,142,857 subordinated units and a 2% general partnership interest (represented by 357,143 equivalent units)	110.6	(0.1)		(105.2)	(5.3)		
Net income attributable to predecessor operations	65.1						65.1
Net income from December 7, 2005 through December 31, 2005		2.7		1.9	0.1		4.7
Other comprehensive income						0.4	0.4
Balance, December 31, 2005	219.8	215.8		(109.7)	(5.6)	0.4	320.7
Net change in parent advances	(25.4)						(25.4)
Acquisition of wholesale propane logistics business	(56.7)						(56.7)
Excess purchase price over acquired assets			(26.3)				(26.3)
Issuance of 200,312 Class C units			5.6				5.6
Proceeds from general partner interest (represented by 4,088 equivalent units)					0.1		0.1
Contributions by unitholders				2.8	0.2		3.0
Distributions to unitholders		(12.8)	(0.1)	(8.8)	(0.4)		(22.1)
Net income attributable to predecessor operations	26.6						26.6

Net income		20.4	0.1	14.1	0.7		35.3
Other comprehensive income						6.9	6.9
Balance, December 31, 2006	164.3	223.4	(20.7)	(101.6)	(5.0)	7.3	267.7
Net change in parent advances	(14.6)						(14.6)
Acquisition of East Texas, Discovery and the Swap	(153.3)	27.0			0.6		(125.7)
Excess purchase price over acquired assets		(118.0)					(118.0)
Acquisition of Momentum Energy Group, Inc.		12.0					12.0
Purchase of units		(0.3)					(0.3)
Issuance of units		0.3					0.3
Issuance of 5,386,732 common units		228.5					228.5
Conversion of Class C units to common units		(20.7)	20.7				
Contributions by unitholders		0.2		0.6			0.8
Distributions to unitholders		(27.0)	(0.2)	(14.1)	(3.2)		(44.5)
Equity-based compensation		0.2					0.2
Net income attributable to predecessor operations	3.6						3.6
Net income (loss)		(16.8)	0.2	(5.0)	2.2		(19.4)
Other comprehensive loss						(22.2)	(22.2)
Balance, December 31, 2007	$	$ 308.8	$	$ (120.1)	$ (5.4)	$ (14.9)	$ 168.4

See accompanying notes to consolidated financial statements.

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DCP MIDSTREAM PARTNERS, LP